



REPLY TO:
LIMETREE BAY TERMINALS, LLC
1 Estate Hope
Christiansted VI 00820-5652

May 3, 2018

HAND DELIVERED

Mr. Norman Williams, Director
Division of Environmental Protection
Department of Planning & Natural Resources
45 Mars Hill
Frederiksted, St. Croix, V.I. 00840-4474

Subject: Authority to Construct for MARPOL Project - Updates

Dear Mr. Williams:

Limetree Bay Terminals, LLC made minor changes to its April 13, 2018 application for an authority to construct for the MARPOL Project, adding Limetree Bay Refining Operating, LLC as a co-permittee and adding the existing Penex Unit, #9 Distillate Desulfurizer, Boiler #5, and Flare No. 3 to the project scope. The updates do not change the regulatory applicability analysis for any unit or the PSD applicability analysis for the project reflected in the April 13 application.

For your convenience, we have included the updates in a revised application for Authority to Construct and supporting documents, including the draft permit conditions for the Authority to Construct.

If you have any questions or require any additional information, please call Ms. Catherine Elizee at (340) 692-3073.

Sincerely,

A handwritten signature in black ink, appearing to read "Darius Sweet", with a long, sweeping horizontal line extending to the right.

Darius Sweet
CEO

DS/CE/jp
Enclosure

cc: Dawn L. Henry, Commissioner (V.I. DPNR) w/o attachment
Angela Arnold (V.I. DPNR) w/ attachment



LIMETREE BAY
T E R M I N A L S

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RECEIVED

5/4/18
DPNR-DEP-AIC

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Darius Sweet
CEO

DS/CE/jp
Enclosure

cc: Dawn L. Henry, Commissioner (V.I. DPNR) w/o attachment
Angela Arnold (V.I. DPNR) w/ attachment

AIR PERMIT APPLICATION

**Limetree Bay Terminals, LLC/
Limetree Bay Refining Operating, LLC**

St. Croix, USVI

MARPOL Project

Submitted to:

Department of Planning and Natural Resources

**45 Estate Mars Hill
Frederiksted, VI 00840**

Prepared by:



**RTP Environmental Associates Inc.
304-A West Millbrook Road
Raleigh, North Carolina 27609**

April 2018

MARPOL Project

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Attachment 1 – Air Permit Application Package

**GOVERNMENT OF THE VIRGIN ISLANDS OF THE UNITED STATES
DEPARTMENT OF PLANNING AND NATURAL RESOURCES
AIR POLLUTION CONTROL**

**APPLICATION FOR:
AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE**

- A. This application must be filled out completely and must be filed in DUPLICATE.
- B. Applications are incomplete unless accompanied by DUPLICATE copies of all plans, specifications and drawings required. Details required for specific equipment are listed on separate forms which are available upon request.

NOTE: INCOMPLETE APPLICATIONS ARE NOT ACCEPTABLE

Date of Application: _____

APPLICATION INFORMATION

1.	Permit to be issued to: (Business License Name of Corporation, Company, Individual Owner or Governmental Agency that is to operate the Equipment): <u>Limetree Bay Terminals, LLC and Limetree Bay Refining Operating, LLC (hereinafter collectively "Limetree Bay Terminals")</u>		
2.	Mailing Address: <u>1 Estate Hope</u> P.O. Box: _____ Island: <u>St. Croix</u>	City: <u>Christiansted</u> Zip: <u>00820-5652</u>	
3.	Address at which the equipment is to be operated: Number: <u>1</u> Street: <u>Estate Hope</u> Island: <u>St. Croix</u> Zip: <u>00820-5652</u>		
4.	Check Type of Organization:	<input checked="" type="checkbox"/> Corporation <input type="checkbox"/> Individual Owner	<input type="checkbox"/> Partnership <input type="checkbox"/> Governmental Agency
5.	Describe General Nature of Business: <u>Petroleum Refinery/Product Storage and Distribution Terminal</u>		
6.	Equipment Description: Pursuant to the Provisions of the U.S. Virgin Islands Code and the Rules and Regulations of the Air Pollution Control Region, application is hereby made for authority to construct and permit to operate the equipment listed below: <u>Limetree Bay Terminals plans to resume operation of certain refinery process units and certain utilities ("MARPOL Project") that are already permitted to operate under Permit No. STX-TV-003-10 and were described in the Title V permit application. Attachment 1 to this application contains detailed information about the MARPOL Project, including a project description, emissions data and calculations, and air regulatory requirements review. Attachment 1 is incorporated by reference into this application. Most of the work to be performed to resume operation is similar to periodically scheduled major maintenance work, which involves repair and replacement of components but do not physically change the unit. However, during the course of the MARPOL Project, there may be changes to the scope of this work. These Application Forms cover the entire work scope needed to resume operation. For emission units for which specific changes will occur, separate USVI DPNR unit specific application forms are provided.</u>		

Area VI: East Sulfur Recovery Plant (H-4745)

A.	1.	<input type="checkbox"/> New Process Equipment and New Air Pollution Control Apparatus <input checked="" type="checkbox"/> New Air Pollution Control Apparatus on Existing Process Equipment <input type="checkbox"/> New Process Equipment with No Control Apparatus <input checked="" type="checkbox"/> Other: Modification of existing process equipment	
	2.	Prior Permit Numbers Covering this Installation. Specify: STX-TV-003-10	
	3.	<table border="1"> <tr> <td>Estimated Starting Date: Construction is expected to commence upon permit issuance</td> <td>Completion: Construction is expected to take 18 months. Operation will commence upon completion of construction; expected to be in or before January 1, 2020</td> </tr> </table>	Estimated Starting Date: Construction is expected to commence upon permit issuance
Estimated Starting Date: Construction is expected to commence upon permit issuance	Completion: Construction is expected to take 18 months. Operation will commence upon completion of construction; expected to be in or before January 1, 2020		

B.	1.	Description of Operation:			
	<p>Changes to the East Sulfur Recovery Plant ("SRP") will increase capacity to 365 long tons per day ("LTPD") and ensure compliance with applicable NSPS subpart Ja SO₂ standard. SRU #3 changes include replacement of air blowers (higher discharge pressure), primary burner (high intensity/oxygen lance to support oxygen enrichment), intra-stage reheaters (steam reheaters), and reloading of catalyst (all reactors). SRU #4 changes include replacement of air blowers (higher discharge pressure), primary burner (high intensity/oxygen lance to support oxygen enrichment), and reloading of catalyst (all reactors). To convert Beavon #2 tailgas treating unit ("TGTU") to a Shell Claus Offgas Treater ("SCOT") type TGTU the hydrogenation reactor catalyst will be replaced and a TGTU steam reheater, quench column, absorber, pumps, and quench water cooler and filter system will be installed. A sulfur pit eductor system will be installed to transport pit vapors from the sulfur pits to the SRU thermal reactor for treatment.</p>				
	2.	Identify Process Equipment:			
	East SRP comprises SRUs #3 & #4, SCOT type TGTU, East incinerator (H-4745), and sulfur pits.				
	3.	Raw Materials (names):			
<p>East SRP is used to recover sulfur from acid gas produced as a byproduct of refinery operations. Sulfur Plant Design Capacity: 365 LTPD sulfur production.</p> <p>Total Pounds per Hour: 31,733 sulfur production Total Pounds per Batch: n/a</p>					
4.	Operating Procedure:				
<input checked="" type="checkbox"/> Continuous 24 Hrs/Day 7 Days per <input checked="" type="checkbox"/> Week <input type="checkbox"/> Month					
<input type="checkbox"/> Batch Hrs/Batch Batches per <input type="checkbox"/> Day <input type="checkbox"/> Week					

C.	Air Contaminant	Emission Level (Ton/Year)*	
		With Control Apparatus	Without Control Apparatus
	Particulate Matter (PM)	4.2	4.2
	Carbon Monoxide (CO)	20	20
	Oxides of Nitrogen (NOx)	24	24
	Sulfur Dioxide (SO ₂)	282	n/a
	Volatile Organic Compounds (VOCs)	1.3	1.3

* Ton per year values represent potential to emit. Control is the SCOT type TGTU and East Incinerator.

D.	1. Describe air pollution control apparatus SCOT type Tailgas treater used to reduce sulfur compounds in the SRU tailgas followed by East Incinerator (H-4745).		
	2. Efficiency of control apparatus	n/a	%
	3. Height of discharge above ground	194.8	ft
	4. Distance from discharge to nearest property line	TBD	ft
	5. Volume of gas discharged into open air	21,470	ft ³ /min at stack conditions
	6. Exit linear velocity at point of discharge	636	ft/min
	7. Temperature at point of discharge	1200 °F	
	8. Will emissions comply with existing local requirements?	Yes	
	9. Initial cost of control apparatus	n/a	
	10. Estimated annual operating cost	n/a	

This application is submitted in accordance with the provisions of the Virgin Islands Code 12, Chapter 9, Air Quality Control Regulations Section §206-20, and to the best of my knowledge and belief is true and correct.

Mailing Address	Zip Code	Phone Number
1 Estate Hope, Christiansted, St. Croix	00820-5652	(340) 692-3000
Title	Printed Name	Signature
Limetree Bay Terminals, LLC Chief Executive Officer Limetree Bay Refining Operating, LLC Manager	Darius Sweet	

Authority to Construct and Permit to Operate

Application for permission to construct, install or alter the equipment and/or control apparatus as set forth above is approved.

Date:

Approved by:

Permit No.:

Supervisor:

**GOVERNMENT OF THE VIRGIN ISLANDS OF THE UNITED STATES
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2.	Mailing Address: <u>1 Estate Hope</u> P.O. Box: _____ City: <u>Christiansted</u> Island: <u>St. Croix</u> Zip: <u>00820-5652</u>
3.	Address at which the equipment is to be operated: Number: <u>1</u> Street: <u>Estate Hope</u> Island: <u>St. Croix</u> Zip: <u>00820-5652</u>
4.	Check Type of Organization: <input checked="" type="checkbox"/> Corporation <input type="checkbox"/> Partnership <input type="checkbox"/> Individual Owner <input type="checkbox"/> Governmental Agency
5.	Describe General Nature of Business: <u>Petroleum Refinery/Product Storage and Distribution Terminal</u>
6.	Equipment Description: Pursuant to the Provisions of the U.S. Virgin Islands Code and the Rules and Regulations of the Air Pollution Control Region, application is hereby made for authority to construct and permit to operate the equipment listed below: <u>Limetree Bay Terminals plans to resume operation of certain refinery process units and certain utilities ("MARPOL Project") that are already permitted to operate under Permit No. STX-TV-003-10 and were described in the Title V permit application. Attachment 1 to this application contains detailed information about the MARPOL Project, including a project description, emissions data and calculations, and air regulatory requirements review. Attachment 1 is incorporated by reference into this application. Most of the work to be performed to resume operation is similar to periodically scheduled major maintenance work, which involves repair and replacement of components but do not physically change the unit. However, during the course of the MARPOL Project, there may be changes to the scope of this work. These Application Forms cover the entire work scope needed to resume operation. For emission units for which specific changes will occur, separate USVI DPNR unit specific application forms are provided.</u>

GAS TURBINE No. 7 (G-3407)

A.	1.	<input type="checkbox"/> New Process Equipment and New Air Pollution Control Apparatus <input checked="" type="checkbox"/> New Air Pollution Control Apparatus on Existing Process Equipment <input type="checkbox"/> New Process Equipment with No Control Apparatus <input type="checkbox"/> Other: Modification of existing process equipment	
	2.	Prior Permit Numbers Covering this Installation. Specify: STX-TV-003-10	
	3.	Estimated Starting Date: 7/2018	Completion: 10/2019

B.	1.	Description of Operation: GT-7 (G-3407) will be retrofitted with Selective Catalytic Reduction ("SCR") to reduce NO _x emissions and comply with the applicable NSPS subpart GG NO _x standard.			
	2.	Identify Process Equipment: GT-7 combustion turbine dual fuel fired (gaseous fuel/No. 2 oil), nominal 20 MW (gross) and unfired heat recovery steam generator ("HRSG").			
	3.	Raw Materials (names): Gaseous fuels and No. 2 oil <div style="display: flex; justify-content: space-between;"> Total Pounds per Hour: n/a Total Pounds per Batch: n/a </div>			
	4.	Operating Procedure: <input checked="" type="checkbox"/> Continuous 24 Hrs/Day 7 Days per <input checked="" type="checkbox"/> Week <input type="checkbox"/> Month <input type="checkbox"/> Batch Hrs/Batch Batches per <input type="checkbox"/> Day <input type="checkbox"/> Week			

C.	Air Contaminant	Emission Level (Ton/Year)*	
		With Control Apparatus	Without Control Apparatus
	Particulate Matter (PM)	6	6
	Carbon Monoxide (CO)**	24	24
	Oxides of Nitrogen (NO _x)	819	n/a
	Sulfur Dioxide (SO ₂)	170	170
	Volatile Organic Compounds (VOCs)**	23	23

*Ton per year values represent potential to emit. Only control is the SCR.

** Based on Table 3.1-1 AP-42 uncontrolled turbine.

D.	1. Describe air pollution control apparatus: SCR: Converts NO _x to nitrogen and water over a catalyst using a selective reductant (e.g., ammonia).		
	2. Efficiency of control apparatus	n/a (varies based on load to comply with NSPS subpart GG) %	
	3. Height of discharge above ground	52	ft
	4. Distance from discharge to nearest property line	TBD	ft
	5. Volume of gas discharged into open air	296,680	ft ³ /min at stack conditions
	6. Exit linear velocity at point of discharge	3.540	ft/min
	7. Temperature at point of discharge	415 °F	
	8. Will emissions comply with existing local requirements?	Yes	
	9. Initial cost of control apparatus	TBD	
	10. Estimated annual operating cost	TBD	

This application is submitted in accordance with the provisions of the Virgin Islands Code 12, Chapter 9, Air Quality Control Regulations Section §206-20, and to the best of my knowledge and belief is true and correct.

Mailing Address	Zip Code	Phone Number
1 Estate Hope, Christiansted, St. Croix	00820-5652	(340) 692-3000
Title	Printed Name	Signature
Limetree Bay Terminals, LLC Chief Executive Officer Limetree Bay Refining Operating, LLC Manager	Darius Sweet	

Authority to Construct and Permit to Operate

Application for permission to construct, install or alter the equipment and/or control apparatus as set forth above is approved.

Date: Approved by:

Permit No.: Supervisor:

**GOVERNMENT OF THE VIRGIN ISLANDS OF THE UNITED STATES
DEPARTMENT OF PLANNING AND NATURAL RESOURCES
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2. Mailing Address: <u>1 Estate Hope</u>		City: <u>Christiansted</u>	
P.O. Box:		Zip: <u>00820-5652</u>	
Island: <u>St. Croix</u>			
3. Address at which the equipment is to be operated:			
Number: <u>1</u>		Street: <u>Estate Hope</u>	
Island: <u>St. Croix</u>		Zip: <u>00820-5652</u>	
4. Check Type of Organization:			
<input checked="" type="checkbox"/> Corporation		<input type="checkbox"/> Partnership	
<input type="checkbox"/> Individual Owner		<input type="checkbox"/> Governmental Agency	
5. Describe General Nature of Business: <u>Petroleum Refinery/Product Storage and Distribution Terminal</u>			
6. Equipment Description: Pursuant to the Provisions of the U.S. Virgin Islands Code and the Rules and Regulations of the Air Pollution Control Region, application is hereby made for authority to construct and permit to operate the equipment listed below:			
Limetree Bay Terminals plans to resume operation of certain refinery process units and certain utilities ("MARPOL Project") that are already permitted to operate under Permit No. STX-TV-003-10 and were described in the Title V permit application. Attachment 1 to this application contains detailed information about the MARPOL Project, including a project description, emissions data and calculations, and air regulatory requirements review. Attachment 1 is incorporated by reference into this application. Most of the work to be performed to resume operation is similar to periodically scheduled major maintenance work, which involves repair and replacement of components but do not physically change the unit. However, during the course of the MARPOL Project, there may be changes to the scope of this work. These Application Forms cover the entire work scope needed to resume operation. For emission units for which specific changes will occur, separate USVI DPNR unit specific application forms are provided.			

GAS TURBINE No. 8 (G-3408)

A.	1.	<input type="checkbox"/> New Process Equipment and New Air Pollution Control Apparatus <input checked="" type="checkbox"/> New Air Pollution Control Apparatus on Existing Process Equipment <input type="checkbox"/> New Process Equipment with No Control Apparatus <input type="checkbox"/> Other: Modification of existing process equipment	
	2.	Prior Permit Numbers Covering this Installation. Specify: STX-TV-003-10	
	3.	Estimated Starting Date: 7/2018	Completion: 10/2019

B.	1. Description of Operation: GT-8 (G-3408) will be retrofitted with Selective Catalytic Reduction ("SCR") to reduce NO _x emissions and comply with the applicable NSPS subpart GG NO _x standard.				
	2. Identify Process Equipment: GT-8 combustion turbine dual fuel fired (gaseous fuel/No. 2 oil), nominal 20 MW (gross) and unfired heat recovery steam generator ("HRSG").				
	3. Raw Materials (names): Gaseous fuel and No. 2 oil <table> <tr> <td>Total Pounds per Hour:</td> <td>n/a</td> <td>Total Pounds per Batch:</td> <td>n/a</td> </tr> </table>	Total Pounds per Hour:	n/a	Total Pounds per Batch:	n/a
	Total Pounds per Hour:	n/a	Total Pounds per Batch:	n/a	
4. Operating Procedure: <input checked="" type="checkbox"/> Continuous 24 Hrs/Day 7 Days per <input checked="" type="checkbox"/> Week <input type="checkbox"/> Month <input type="checkbox"/> Batch Hrs/Batch Batches per <input type="checkbox"/> Day <input type="checkbox"/> Week					

C.	Air Contaminant	Emission Level (Ton/Year)*	
		With Control Apparatus	Without Control Apparatus
	Particulate Matter (PM)	7	7
	Carbon Monoxide (CO)**	42	42
	Oxides of Nitrogen (NO _x)	1060	n/a
	Sulfur Dioxide (SO ₂)	211	211
	Volatile Organic Compounds (VOCs)**	48	48

* Ton per year values represent potential to emit. Only control is the SCR.

** Based on Table 3.1-1 AP-42 uncontrolled turbine.

D.	1.	Describe air pollution control apparatus SCR: Converts NO _x to nitrogen and water over a catalyst using a selective reductant (e.g., ammonia)	
	2.	Efficiency of control apparatus	n/a (varies based on load to comply with NSPS subpart GG) %
	3.	Height of discharge above ground	49.9 ft
	4.	Distance from discharge to nearest property line	TBD ft
	5.	Volume of gas discharged into open air	369,100 ft ³ /min at stack conditions
	6.	Exit linear velocity at point of discharge	4,607 ft/min
	7.	Temperature at point of discharge	415 °F
	8.	Will emissions comply with existing local requirements?	Yes
	9.	Initial cost of control apparatus	TBD
	10.	Estimated annual operating cost	TBD

This application is submitted in accordance with the provisions of the Virgin Islands Code 12, Chapter 9, Air Quality Control Regulations Section §206-20, and to the best of my knowledge and belief is true and correct.

Mailing Address	Zip Code	Phone Number
1 Estate Hope, Christiansted, St. Croix	00820-5652	(340) 692-3000
Title	Printed Name	Signature
Limetree Bay Terminals, LLC Chief Executive Officer Limetree Bay Refining Operating, LLC Manager	Darius Sweet	

Authority to Construct and Permit to Operate

Application for permission to construct, install or alter the equipment and/or control apparatus as set forth above is approved.

Date:

Approved by:

Permit No.:

Supervisor:

**GOVERNMENT OF THE VIRGIN ISLANDS OF THE UNITED STATES
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2. Mailing Address: <u>1 Estate Hope</u>		City: <u>Christiansted</u>	
P.O. Box:		Island: <u>St. Croix</u>	
Zip: <u>00820-5652</u>			
3. Address at which the equipment is to be operated:			
Number: <u>1</u>		Street: <u>Estate Hope</u>	
Island: <u>St. Croix</u>		Zip: <u>00820-5652</u>	
4. Check Type of Organization:			
<input checked="" type="checkbox"/> Corporation		<input type="checkbox"/> Partnership	
<input type="checkbox"/> Individual Owner		<input type="checkbox"/> Governmental Agency	
5. Describe General Nature of Business: <u>Petroleum Refinery/Product Storage and Distribution Terminal</u>			
6. Equipment Description: Pursuant to the Provisions of the U.S. Virgin Islands Code and the Rules and Regulations of the Air Pollution Control Region, application is hereby made for authority to construct and permit to operate the equipment listed below:			
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A.	1.	<input type="checkbox"/> New Process Equipment and New Air Pollution Control Apparatus <input checked="" type="checkbox"/> New Air Pollution Control Apparatus on Existing Process Equipment <input type="checkbox"/> New Process Equipment with No Control Apparatus <input type="checkbox"/> Other: Modification of existing process equipment	
	2.	Prior Permit Numbers Covering this Installation. Specify: STX-TV-003-10	
	3.	Estimated Starting Date: TBD	Completion: 10/2019

B.	1. Description of Operation:	Boiler No. 5 (B-1155) will be retrofitted with NO _x control technology (e.g., Selective Catalytic Reduction ("SCR") or low NO _x burners) to comply with the applicable NSPS subpart D NO _x standard.						
	2. Identify Process Equipment:	Boiler No. 5 (B-1155) will be fired with gaseous fuel						
	3. Raw Materials (names):	Fuel gas (NSPS subpart J compliant, 162 ppmv H ₂ S) and gaseous fuel						
	Total Pounds per Hour:	n/a	Total Pounds per Batch:		n/a			
4. Operating Procedure:	<input checked="" type="checkbox"/> Continuous 24 Hrs/Day 7 Days per <input checked="" type="checkbox"/> Week <input type="checkbox"/> Month <input type="checkbox"/> Batch Hrs/Batch Batches per <input type="checkbox"/> Day <input type="checkbox"/> Week							

C.	Air Contaminant	Emission Level (Ton/Year)*	
		With Control Apparatus	Without Control Apparatus
	Particulate Matter (PM)	3	3
	Carbon Monoxide (CO)	146	146
	Oxides of Nitrogen (NOx)	355	n/a
	Sulfur Dioxide (SO ₂)	59	59
	Volatile Organic Compounds (VOCs)	10	10

12

D.	1. Describe air pollution control apparatus		
	<u>NOx Control Technology</u>		
	<ul style="list-style-type: none"> • SCR: Converts NOx to nitrogen and water over a catalyst using a selective reductant (e.g., ammonia), or • Low NOx Burner: Creates reducing zones within the fuel combustion region to reduce the relative NOx emissions rate. 		
	2. Efficiency of control apparatus	n/a	%
	3. Height of discharge above ground	194.8	ft
	4. Distance from discharge to nearest property line	TBD	ft
	5. Volume of gas discharged into open air	176,430	ft ³ /min at stack conditions
	6. Exit linear velocity at point of discharge	3.509	ft/min
	7. Temperature at point of discharge	400 °F	
	8. Will emissions comply with existing local requirements?	Yes	
9. Initial cost of control apparatus	TBD		
10. Estimated annual operating cost	TBD		

This application is submitted in accordance with the provisions of the Virgin Islands Code 12, Chapter 9, Air Quality Control Regulations Section §206-20, and to the best of my knowledge and belief is true and correct.

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1 Estate Hope, Christiansted, St. Croix	00820-5652	(340) 692-3000
Title	Printed Name	Signature
Limetree Bay Terminals, LLC Chief Executive Officer Limetree Bay Refining Operating, LLC Manager	Darius Sweet	

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2.	Mailing Address: <u>1 Estate Hope</u> P.O. Box: _____ City: <u>Christiansted</u> Island: <u>St. Croix</u> Zip: <u>00820-5652</u>
3.	Address at which the equipment is to be operated: Number: <u>1</u> Street: <u>Estate Hope</u> Island: <u>St. Croix</u> Zip: <u>00820-5652</u>
4.	Check Type of Organization: <input checked="" type="checkbox"/> Corporation <input type="checkbox"/> Partnership <input type="checkbox"/> Individual Owner <input type="checkbox"/> Governmental Agency
5.	Describe General Nature of Business: <u>Petroleum Refinery/Product Storage and Distribution Terminal</u>
6.	Equipment Description: Pursuant to the Provisions of the U.S. Virgin Islands Code and the Rules and Regulations of the Air Pollution Control Region, application is hereby made for authority to construct and permit to operate the equipment listed below: <u>Limetree Bay Terminals plans to resume operation of certain refinery process units and certain utilities ("MARPOL Project") that are already permitted to operate under Permit No. STX-TV-003-10 and were described in the Title V permit application. Attachment 1 to this application contains detailed information about the MARPOL Project, including a project description, emissions data and calculations, and air regulatory requirements review. Attachment 1 is incorporated by reference into this application. Most of the work to be performed to resume operation is similar to periodically scheduled major maintenance work, which involves repair and replacement of components but do not physically change the unit. However, during the course of the MARPOL Project, there may be changes to the scope of this work. These Application Forms cover the entire work scope needed to resume operation. For emission units for which specific changes will occur, separate USVI DPNR unit specific application forms are provided.</u>

A.	1.	<input type="checkbox"/> New Process Equipment and New Air Pollution Control Apparatus <input checked="" type="checkbox"/> New Air Pollution Control Apparatus on Existing Process Equipment <input type="checkbox"/> New Process Equipment with No Control Apparatus <input type="checkbox"/> Other: Modification of existing process equipment	
	2.	Prior Permit Numbers Covering this Installation. Specify: STX-TV-003-10	
	3.	Estimated Starting Date: TBD	Completion: 10/2019

B.	1. Description of Operation:	Boiler No. 8 (B-3303) will be retrofitted with NO _x control technology (e.g., Selective Catalytic Reduction ("SCR") or low NO _x burners) to comply with the applicable NSPS subpart D NO _x standard.				
	2. Identify Process Equipment:	Boiler No. 8 (B-3303) will be fired with gaseous fuel				
	3. Raw Materials (names):	Fuel gas (NSPS subpart J compliant, 162 ppmv H ₂ S) and gaseous fuel				
	Total Pounds per Hour:	n/a	Total Pounds per Batch:	n/a		
	4. Operating Procedure:	<input checked="" type="checkbox"/> Continuous 24 Hrs/Day 7 Days per <input checked="" type="checkbox"/> Week <input type="checkbox"/> Month <input type="checkbox"/> Batch Hrs/Batch Batches per <input type="checkbox"/> Day <input type="checkbox"/> Week				

C.	Air Contaminant	Emission Level (Ton/Year)*	
		With Control Apparatus	Without Control Apparatus
	Particulate Matter (PM)	3	3
	Carbon Monoxide (CO)	146	146
	Oxides of Nitrogen (NOx)	355	n/a
	Sulfur Dioxide (SO ₂)	59	59
	Volatile Organic Compounds (VOCs)	10	10

15

D.	1. Describe air pollution control apparatus <u>NOx Control Technology</u>		
	<ul style="list-style-type: none"> • SCR: Converts NOx to nitrogen and water over a catalyst using a selective reductant (e.g., ammonia), or • Low NOx Burner: Creates reducing zones within the fuel combustion region to reduce the relative NOx emissions rate. 		
	2. Efficiency of control apparatus	n/a	%
	3. Height of discharge above ground	194.8	ft
	4. Distance from discharge to nearest property line	TBD	ft
	5. Volume of gas discharged into open air	333,610	ft ³ /min at stack conditions
	6. Exit linear velocity at point of discharge	2.520	ft/min
	7. Temperature at point of discharge	400 °F	
	8. Will emissions comply with existing local requirements?	Yes	
	9. Initial cost of control apparatus	TBD	
10. Estimated annual operating cost	TBD		

This application is submitted in accordance with the provisions of the Virgin Islands Code 12, Chapter 9, Air Quality Control Regulations Section §206-20, and to the best of my knowledge and belief is true and correct.

Mailing Address	Zip Code	Phone Number
I Estate Hope, Christiansted, St. Croix	00820-5652	(340) 692-3000
Title	Printed Name	Signature
Limetree Bay Terminals, LLC Chief Executive Officer Limetree Bay Refining Operating, LLC Manager	Darius Sweet	

Authority to Construct and Permit to Operate

Application for permission to construct, install or alter the equipment and/or control apparatus as set forth above is approved.

Date: Approved by:

Permit No.: Supervisor:

**GOVERNMENT OF THE VIRGIN ISLANDS OF THE UNITED STATES
DEPARTMENT OF PLANNING AND NATURAL RESOURCES
AIR POLLUTION CONTROL**

**APPLICATION FOR:
AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE**

- A. This application must be filled out completely and must be filed in DUPLICATE.
B. Applications are incomplete unless accompanied by DUPLICATE copies of all plans, specifications and drawings required. Details required for specific equipment are listed on separate forms which are available upon request.

NOTE: INCOMPLETE APPLICATIONS ARE NOT ACCEPTABLE

Date of Application: _____

APPLICATION INFORMATION

1.	Permit to be issued to: (Business License Name of Corporation, Company, Individual Owner or Governmental Agency that is to operate the Equipment): <u>Limetree Bay Terminals, LLC and Limetree Bay Refining Operating, LLC (hereinafter collectively "Limetree Bay Terminals")</u>
2.	Mailing Address: <u>1 Estate Hope</u> P.O. Box: _____ City: <u>Christiansted</u> Island: <u>St. Croix</u> Zip: <u>00820-5652</u>
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5.	Describe General Nature of Business: <u>Petroleum Refinery/Product Storage and Distribution Terminal</u>
6.	Equipment Description: Pursuant to the Provisions of the U.S. Virgin Islands Code and the Rules and Regulations of the Air Pollution Control Region, application is hereby made for authority to construct and permit to operate the equipment listed below: <u>Limetree Bay Terminals plans to resume operation of certain refinery process units and certain utilities ("MARPOL Project") that are already permitted to operate under Permit No. STX-TV-003-10 and were described in the Title V permit application. Attachment 1 to this application contains detailed information about the MARPOL Project, including a project description, emissions data and calculations, and air regulatory requirements review. Attachment 1 is incorporated by reference into this application. Most of the work to be performed to resume operation is similar to periodically scheduled major maintenance work, which involves repair and replacement of components but do not physically change the unit. However, during the course of the MARPOL Project, there may be changes to the scope of this work. These Application Forms cover the entire work scope needed to resume operation. For emission units for which specific changes will occur, separate USVI DPNR unit specific application forms are provided.</u>

A.	1.	<input type="checkbox"/> New Process Equipment and New Air Pollution Control Apparatus <input checked="" type="checkbox"/> New Air Pollution Control Apparatus on Existing Process Equipment <input type="checkbox"/> New Process Equipment with No Control Apparatus <input checked="" type="checkbox"/> Other: Modification of existing process equipment	
	2.	Prior Permit Numbers Covering this Installation. Specify: STX-TV-003-10	
	3.	Estimated Starting Date: TBD	Completion: 10/2019

B.	1. Description of Operation:	Boiler No. 9 (B-3304) will be retrofitted with NO _x control technology (e.g., Selective Catalytic Reduction ("SCR"), low NO _x burners) to comply with the applicable NSPS subpart D NO _x standard.				
	2. Identify Process Equipment:	Boiler No. 9 (B-3304) will be fired with gaseous fuel				
	3. Raw Materials (names):	Fuel gas (NSPS subpart J compliant, 162 ppmv H ₂ S) and gaseous fuel				
	Total Pounds per Hour:	n/a	Total Pounds per Batch:	n/a		
	4. Operating Procedure:	<input checked="" type="checkbox"/> Continuous 24 Hrs/Day 7 Days per <input checked="" type="checkbox"/> Week <input type="checkbox"/> Month <input type="checkbox"/> Batch Hrs/Batch Batches per <input type="checkbox"/> Day <input type="checkbox"/> Week				

C.	Air Contaminant	Emission Level (Ton/Year)*	
		With Control Apparatus	Without Control Apparatus
	Particulate Matter (PM)	3	3
	Carbon Monoxide (CO)	146	146
	Oxides of Nitrogen (NOx)	355	n/a
	Sulfur Dioxide (SO ₂)	59	59
	Volatile Organic Compounds (VOCs)	10	10

18

D.	1. Describe air pollution control apparatus		
	<u>NO_x Control Technology</u>		
	<ul style="list-style-type: none"> • SCR: Converts NO_x to nitrogen and water over a catalyst using a selective reductant (e.g., ammonia), or • Low NO_x Burner: Creates reducing zones within the fuel combustion region to reduce the relative NO_x emissions rate. 		
	2. Efficiency of control apparatus	n/a	%
	3. Height of discharge above ground	194.8	ft
	4. Distance from discharge to nearest property line	TBD	ft
	5. Volume of gas discharged into open air	333,610	ft ³ /min at stack conditions
	6. Exit linear velocity at point of discharge	2,520	ft/min
	7. Temperature at point of discharge	400° F	
	8. Will emissions comply with existing local requirements?	Yes	
9. Initial cost of control apparatus	TBD		
10. Estimated annual operating cost	TBD		

This application is submitted in accordance with the provisions of the Virgin Islands Code 12, Chapter 9, Air Quality Control Regulations Section §206-20, and to the best of my knowledge and belief is true and correct.

Mailing Address	Zip Code	Phone Number
1 Estate Hope, Christiansted, St. Croix	00820-5652	(340) 692-3000
Title	Printed Name	Signature
Limetree Bay Terminals, LLC Chief Executive Officer Limetree Bay Refining Operating, LLC Manager	Darius Sweet	

Authority to Construct and Permit to Operate

Application for permission to construct, install or alter the equipment and/or control apparatus as set forth above is approved.

Date:

Approved by:

Permit No.:

Supervisor:

**GOVERNMENT OF THE VIRGIN ISLANDS OF THE UNITED STATES
DEPARTMENT OF PLANNING AND NATURAL RESOURCES
AIR POLLUTION CONTROL**

**APPLICATION FOR:
AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE**

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B. Applications are incomplete unless accompanied by DUPLICATE copies of all plans, specifications and drawings required. Details required for specific equipment are listed on separate forms which are available upon request.

NOTE: INCOMPLETE APPLICATIONS ARE NOT ACCEPTABLE

Date of Application: _____

APPLICATION INFORMATION

1.	<p>Permit to be issued to: (Business License Name of Corporation, Company, Individual Owner or Governmental Agency that is to operate the Equipment): <u>Limetree Bay Terminals, LLC and Limetree Bay Refining Operating, LLC (hereinafter collectively "Limetree Bay Terminals")</u></p>
2.	<p>Mailing Address: <u>1 Estate Hope</u></p> <p>P.O. Box: _____ City: <u>Christiansted</u></p> <p>Island: <u>St. Croix</u> Zip: <u>00820-5652</u></p>
3.	<p>Address at which the equipment is to be operated:</p> <p>Number: <u>1</u> Street: <u>Estate Hope</u></p> <p>Island: <u>St. Croix</u> Zip: <u>00820-5652</u></p>
4.	<p>Check Type of Organization: <input checked="" type="checkbox"/> Corporation <input type="checkbox"/> Partnership</p> <p style="padding-left: 300px;"><input type="checkbox"/> Individual Owner <input type="checkbox"/> Governmental Agency</p>
5.	<p>Describe General Nature of Business:</p> <p><u>Petroleum Refinery/Product Storage and Distribution Terminal</u></p>
6.	<p>Equipment Description: Pursuant to the Provisions of the U.S. Virgin Islands Code and the Rules and Regulations of the Air Pollution Control Region, application is hereby made for authority to construct and permit to operate the equipment listed below:</p> <p><u>Limetree Bay Terminals plans to resume operation of certain refinery process units and certain utilities ("MARPOL Project") that are already permitted to operate under Permit No. STX-TV-003-10 and were described in the Title V permit application. Attachment 1 to this application contains detailed information about the MARPOL Project, including a project description, emissions data and calculations, and air regulatory requirements review. Attachment 1 is incorporated by reference into this application. Most of the work to be performed to resume operation is similar to periodically scheduled major maintenance work, which involves repair and replacement of components but do not physically change the unit. However, during the course of the MARPOL Project, there may be changes to the scope of this work. These Application Forms cover the entire work scope needed to resume operation. For emission units for which specific changes will occur, separate USVI DPNR unit specific application forms are provided.</u></p>

PROCESS UNIT EQUIPMENT LEAKS (5 CDU, 7 DD, 3 PLAT, 6 DD, 4 PLAT, DCU, PENEX, 9 DD, 2 GRU, GAS TREATMENT (UNIT NO. 4800), GAS TREATMENT (UNIT NO. 5800), AND #6, & #7 AMINE UNITS)

A.	1.	<input type="checkbox"/> New Process Equipment and New Air Pollution Control Apparatus <input type="checkbox"/> New Air Pollution Control Apparatus on Existing Process Equipment <input type="checkbox"/> New Process Equipment with No Control Apparatus <input checked="" type="checkbox"/> Other: Modification of existing process equipment	
	2.	Prior Permit Numbers Covering this Installation. Specify: STX-TV-003-10	
	3.	Estimated Starting Date: Construction is expected to commence upon permit issuance	Completion: Construction is expected to take 18 months. Operation will commence upon completion of construction; expected to be in or before January 1, 2020

B.	1.	Description of Operation: Refer to Attachment 1 (Section 2.1 through Section 2.16)								
	2.	Identify Process Equipment: Refer to Table 1 in Appendix C of Attachment 1 and Title V permit (STX-TV-003-10)								
	3.	Raw Materials (names): n/a								
	4.	Operating Procedure:								
	<input checked="" type="checkbox"/>	Continuous	24	Hrs/Day	7	Days per	<input checked="" type="checkbox"/>	Week	<input type="checkbox"/>	Month
	<input type="checkbox"/>	Batch		Hrs/Batch		Batches per	<input type="checkbox"/>	Day	<input type="checkbox"/>	Week

C.	Air Contaminant	Emission Level (Ton/Year)	
		With Control Apparatus	Without Control Apparatus
	Particulate Matter (PM)	n/a	n/a
	Carbon Monoxide (CO)	n/a	n/a
	Oxides of Nitrogen (NOx)	n/a	n/a
	Sulfur Dioxide (SO ₂)	n/a	n/a
	Volatile Organic Compounds (VOCs)	n/a	n/a*

* Control of equipment component emissions (fugitive emissions) is achieved through the NSPS subpart GGG work practice and as such is not quantifiable for purposes of determining PTE

D.	1.	Describe air pollution control apparatus Refer to Attachment 1 and Title V Permit	
	2.	Efficiency of control apparatus	n/a %
	3.	Height of discharge above ground	n/a ft
	4.	Distance from discharge to nearest property line	n/a ft
	5.	Volume of gas discharged into open air	n/a ft ³ /min at stack conditions
	6.	Exit linear velocity at point of discharge	n/a ft/min
	7.	Temperature at point of discharge	n/a
	8.	Will emissions comply with existing local requirements?	Yes
	9.	Initial cost of control apparatus	n/a
	10.	Estimated annual operating cost	n/a

This application is submitted in accordance with the provisions of the Virgin Islands Code 12, Chapter 9, Air Quality Control Regulations Section §206-20, and to the best of my knowledge and belief is true and correct.

Mailing Address	Zip Code	Phone Number
1 Estate Hope, Christiansted, St. Croix	00820-5652	(340) 692-3000
Title	Printed Name	Signature
Limetree Bay Terminals, LLC Chief Executive Officer Limetree Bay Refining Operating, LLC Manager	Darius Sweet	

Authority to Construct and Permit to Operate

Application for permission to construct, install or alter the equipment and/or control apparatus as set forth above is approved.

Date:

Approved by:

Permit No.:

Supervisor:

Attachment 1
Air Permit Application Package

AIR PERMIT APPLICATION

Limetree Bay Terminals, LLC/
Limetree Bay Refining Operating, LLC
St. Croix, USVI

MARPOL Project

Submitted to:

**Department of Planning and Natural Resources
45 Estate Mars Hill
Frederiksted, VI 00840**

Prepared by:



**RTP Environmental Associates Inc.
304-A West Millbrook Road
Raleigh, North Carolina 27609**

April 2018

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1.0 Introduction

Limetree Bay Terminals, LLC/Limetree Bay Refining Operating, LLC (hereinafter “Limetree Bay Terminals”) is submitting this permit application, pursuant to 12 Virgin Islands Rules and Regulations (“VIRR”) §§ 206-20 and 206-31, to construct a project associated with resuming operations of some of the St. Croix facility refining process units (the “MARPOL” project). The proposed project involves alterations to existing emissions units but does not involve installation of any new emissions units.

The St. Croix facility is an existing major stationary source¹ and is the holder of Title V Air Permit No. STX-TV-003-10, which was formally transferred to Limetree Bay Terminals on March 9, 2016. Consistent with prior guidance from the U.S. Virgin Islands (“USVI”) Department of Protection and Natural Resources (“DPNR”), Limetree Bay Terminals is applying for an Authority to Construct for the proposed MARPOL Project, as described below, and will subsequently modify the Title V permit to incorporate the terms of this Permit in accordance with 12 VIRR §§ 206-21(b) and 206-82.

1.1. Background

On January 4, 2016, Limetree Bay Terminals purchased assets from HOVENSA L.L.C. (“HOVENSA”), including the refinery process units and utilities that had been idled in 2011 and 2012. The asset sale to Limetree Bay Terminals was subject to an agreement between the Government of the Virgin Islands and Limetree Bay Terminals for the operation of the assets acquired by Limetree Bay Terminals (“Operating Agreement”), which was executed by the USVI Government and Limetree Bay Terminals on December 1, 2015. Under the Operating Agreement, Limetree Bay Terminals is contractually obligated to evaluate the potential for resuming operation of the Refinery during a period ending no later than December 2018.

Based on the evaluation, Limetree Bay Terminals plans to resume operation of some of the existing refinery process units and certain utilities. The refinery process units and utilities that will cause emissions of air pollutants and are proposed to resume operation are listed in Table 1-1 (*i.e.*, emissions units), which also includes emissions units that are currently operating and will support the MARPOL Project. Some emissions units are expected to be “modified” as that term is used in the regulations. During the course of the proposed MARPOL Project, there may be changes to the scope of work to an emissions unit that are considered modifications. Likewise, the scope of work to resume operation at a refinery process unit or utility may also constitute an “alteration” for purposes of 12 VIRR §206-20(a).

¹ The Limetree Bay Terminals St. Croix facility is in a listed source category (petroleum refinery) and has the potential to emit 100 tons per year or more of any regulated NSR pollutant [§52.21(b)(1)(i)].

Table 1-1. Summary of MARPOL Project Modified and Affected Process Units

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ²	Overview of Proposed Modifications ³
#5 Crude Unit (#5 CDU)	- Heater H-3101A - Heater H-3101B - #5 CDU Process Unit (fugitives)	- Affected - Affected - Modified	- None - None - Install tie-ins from #5CDU to #6 CDU desalter - Install tie-ins from #5CDU to #6 CDU overhead compressor
#3 Vacuum Unit (#3 VAC)	- Heater H-4201 - Heater H-4202 - #3 VAC Process Unit (fugitives)	- Affected - Affected - Modified	- None - None - Replace impeller in the vacuum booster pumps (P-4234 A/B)
#7 Distillate Desulfurizer (#7 DD)	- Heater H-4301A - Heater H-4301B - Heater H-4302 - #7 DD Process Unit (fugitives)	- Affected - Affected - Affected - Modified	- None - None - None - Install packaged chiller on compressor suction - Install on-line sulfur analyzer on reactor rundown
#3 Platformer (#3 Plat)	- Heater H-4401 - Heater H-4402 - 3 Plat Process Unit (fugitives)	- Affected - Affected - Modified	- None - None - Repurpose #3 Plat Hydrobon section to a light naphtha hydrotreater and #3 Plat reformer to isomerization unit - Install new reactor charge pumps, reactor feed / effluent heat exchangers, reactor charge heat exchanger, recycle gas dryer regeneration feed / effluent heat exchanger, recycle gas dryer regeneration cooler, and recycle gas driers.

² Additional analysis may result in an update to the status of the listed affected emission units with regards to possible changes that are required.

³ The modifications that are summarized are based on the current definition of the project. Additional changes within a given process unit may be identified as part of the detailed design work. The Marpol Project will result in work being performed on affected units, but that work is not expected to be a modification.

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ²	Overview of Proposed Modifications ³
#6 Distillate Desulfurizer (#6 DD)	<ul style="list-style-type: none"> - Heater H-4601A - Heater H-4601B - Heater H-4602 - Compressor C-4601A - Compressor C-4601B - Compressor C-4601C - #6 DD Process Unit (fugitives) 	<ul style="list-style-type: none"> - Affected - Affected - Affected - Affected - Affected - Affected - Modified 	<ul style="list-style-type: none"> - None - None - None - None - None - None - Install piping and control valves to allow for feed bypass around inlet exchangers - Install additional effluent exchanger - Install hydrogen quench line into reactors - Install on-line sulfur analyzer on reactor rundown
#4 Platformer (#4 Plat)	<ul style="list-style-type: none"> - Heater H-5401 - Heater H-5402 - Heater H-5451 - Heater H-5452 - Heater H-5453 - Heater H-5454 - Heater H-5455 - #4 Plat Process Fugitives 	<ul style="list-style-type: none"> - Affected - Affected - Affected - Affected - Affected - Affected - Affected - Modified 	<ul style="list-style-type: none"> - None - None - None - None - None - None - None - Use #4 Plat Hydrobon section as a naphtha hydrotreater; use #4 Plat reformer section as a naphtha reformer - Install chloride gas treaters - Install chloride LPG treaters
Delayed Coker Unit (DCU)	<ul style="list-style-type: none"> - Heater H-8501A - Heater H-8501B - DCU Vent - DCU Process Fugitives 	<ul style="list-style-type: none"> - Affected - Affected - Affected - Modified 	<ul style="list-style-type: none"> - None - None - None - Install fuel oil feed system - Install blowdown eductor (to comply with MACT Subpart CC) system (2 psi vent target) - Install additional instrumentation to support coke drum deheading process

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ²	Overview of Proposed Modifications ³
Penex Unit	- Heater H-202 - Compressor C-200A - Compressor C-200B - Compressor C-200C - Penex Process Fugitives	- Affected - Affected - Affected - Affected - Modified	- None - None - None - None - Install additional heat exchange, modify fractionator stabilizers, reactor distributors, and piping
#9 Distillate Desulfurizer (#9 DD)	- Heater H-5301A - Heater H-5301B - Heater H-5302 - #9 DD Process Unit (fugitives)	- Affected - Affected - Affected - Affected	- None - None - None - None
Boilers	- #5 Boiler (B-1155) - #8 Boiler (B-3303) - #9 Boiler (B-3304) - #10 Boiler (B-3701)	- Affected - Modify - Modify - Affected	- Install NO _x control technology (e.g., low NO _x burners or Selective Catalytic Reduction (“SCR”)) as needed to comply with NSPS subpart D - Install NO _x control technology (e.g., low NO _x burners or Selective Catalytic Reduction (“SCR”)) as needed to comply with NSPS subpart D - Install NO _x control technology as needed to comply with NSPS subpart D - None
Powerhouse 2 - Gas Turbine/Steam Generators	- GT No. 7 (G-3407) ⁴ - GT No. 8 (G-3408) ⁴ - GT No. 9 (G-3409) - GT No. 10 (G-3410) - GT No. 13 (G-3413)	- Modify - Modify - Affected - Affected - Affected	- Install SCR to comply with NSPS subpart GG - Install “SCR” to comply with NSPS subpart GG - None - None - None
Flares	- Flare 3 - Flare 5 - Flare 7 ⁴ - LPG Flare - Low-Pressure FCC Flare - Ground Flare	- Affected - Affected - Affected - Affected - Affected - Affected	- None - None - None - None - None - None

⁴ An emissions unit that is currently in operation and is not resuming operation.

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ²	Overview of Proposed Modifications ³
Tanks	- Multiple ⁵ (see Appendix C for listing)	- Affected	- Tanks
# 2 Gas Recovery Unit (#2 GRU)	- #2 GRU Process Fugitives	- Modified	- Install jumper connecting the product separator to the feed gas knockout drum at the high-pressure amine contactor
Amine Units	- Gas Treatment (Unit No. 4800 #4 Amine Unit)	- Modified	- Replace #4/5 Amine Unit flash drum with larger drum and replace #4/5 Amine Unit rich amine pump (P-4837 A/B) or install a third pump to comply with NSPS subpart J.
	- Gas Treatment (Unit No. 5800 #5 Amine Unit)	- Modified	
	- #6 Amine Unit	- Modified	
	- #7 Amine Unit	- Affected	
East Sulfur Recovery Plant	- # 3 & #4 SRU / #2 Beavon / East Incinerator / Sulfur pits	- Modified	<ul style="list-style-type: none"> - #3 SRU: Replace air blowers (higher discharge pressure), primary burner (high intensity/oxygen lance to support oxygen enrichment), intra-stage reheaters (steam reheaters), and reloading of catalyst (all reactors) - #4 SRU: Replace air blowers (higher discharge pressure), primary burner (high intensity/oxygen lance to support oxygen enrichment), and reloading of catalyst (all reactors) - #2 Beavon: Convert tailgas treating unit ("TGTU") to a Shell Claus Offgas Treater ("SCOT") type TGTU by changing the hydrogenation reactor catalyst, replace fired TGTU reheater with steam reheater, install quench column, absorber, pumps, and quench water cooler and filter system - Install sulfur pit eductor system to transport pit vapors from sulfur pits to SRU thermal reactor

⁵ Some tanks are currently in operation, others may need repair prior to return to service.

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ²	Overview of Proposed Modifications ³
East Sulfur Storage Area	- East Sulfur Storage Area	- Affected	- None
Sulfur storage & Ship Loading	- Sulfur storage & Ship Loading	- Affected	- None
Coke Handling	- Coke handling, storage, and loading system	- Affected	- None
Advance Wastewater Treatment System	- Advanced Wastewater Treatment System ⁶	- Affected	- None
	- #4 Sour Water Stripper (“SWS”)	- Affected	- None
	- #5 SWS	- Affected	- None
Marine Loading	- Marine Loading ⁴	- Affected	- None

⁶ An emissions unit that is currently in operation, portions of which may be resuming operation.

Accordingly, Limetree Bay Terminals is applying for an Authority to Construct under 12 VIRR §206-20 and an approval to construct or modify under 12 VIRR §206-31 for all of the work scope needed for the MARPOL Project as further discussed in this application.

In 1997, Annex VI to the International Convention for the Prevention of Pollution from Ships (the “MARPOL Convention”) was adopted. Annex VI’s objective was to reduce air emissions from shipping. Most recently, the International Maritime Organization (“IMO”) amended Annex VI to set a global sulfur content limit of 0.50 percent m/m (mass by mass) on fuel oil that is combusted on ships, reducing the existing 3.5 percent limit. This lower sulfur content limit is set to go into effect on January 1, 2020 and will significantly reduce SO_x emissions from ships. The United States is a signatory to MARPOL generally and to Annex VI and has adopted regulations to implement this requirement, as have many other nations. Because of the relatively short lead time for compliance and the significant drop in the global sulfur standard⁷, there is expected to be a shortfall of compliant fuel at the outset of the program.

The St. Croix facility is a complex, integrated petroleum refinery consisting of refinery process units and various supporting operations including sulfur recovery plants, steam and electric power generation via boilers and combustion turbine cogeneration units, wastewater treatment and a marine terminal. In 2010, the refinery’s crude oil permitted processing rate was 525,000 barrels per calendar day (“BPCD”), including generally smaller equipment on the west side of the facility (“West Side”) and generally larger equipment on the east side of the facility (“East Side”). Some of the refinery process units on the West Side were idled in early 2011, reducing the refinery’s crude charge rate to approximately 350,000 BPCD, and all remaining refinery process units at the facility were idled in early 2012. Terminal operations, local product distribution, and the emissions units that support those operations have continued to operate.

The proposed MARPOL Project involves alterations that facilitate resuming refining operations at the St. Croix facility in order to supply transportation fuel to meet increased market demand, including demand created by the 0.50% m/m global sulfur content limit for fuel oil combusted on ships.

1.2. Project Overview

A listing of the refinery process units and emissions units that will resume operation as part of the proposed MARPOL Project is presented in Table 1-1. Included with this list are notations as to whether the emissions unit will be altered or is listed simply because its actual emissions may be affected by the project. Table 1-1 also includes a description of the alterations being made in the process/emissions unit, if any. Table 1-1 also includes emissions units that are currently in operation but will support the MARPOL Project.

⁷ The IMO only confirmed the 0.50 percent level on October 27, 2016, leaving less than the standard four year benchmark to be able to produce and distribute a compliant fuel.

As shown in Table 1-1, with the exception of the East Sulfur Recovery Plant, No. 7 Gas Turbine (“GT-7”), and GT-8, and #5, #8 and #9 Boilers, the physical changes (*i.e.*, modifications) that are planned as part of the project include maintenance, repair, and component replacement activities involving existing process equipment (*i.e.*, reactors, fractionators, heat exchangers, process vessels, pumps, valves, etc.) and addition of new components within existing refinery process unit or utility.⁸ No modifications will be made to any process heaters or stationary, reciprocating internal combustion engines.

The East Sulfur Recovery Plant, which comprises the Nos. #3 & #4 Sulfur Recovery Units (“SRUs”), #2 Beavon Unit (“#2 Beavon”), and the East Incinerator (H-4745), will be modified by altering the #3 & #4 SRUs converting the #2 Beavon, which is an air pollution control device previously used to treat tail gas from the SRUs to a Shell Claus Offgas Treating (“SCOT”) type tail gas treating unit (“TGTU”) to comply with NSPS subpart Ja, and installing an ejector system on the sulfur pits.

Alterations will be made to #5, #8 and #9 Boilers to comply with NSPS subpart D and to GT-7 and GT-8 to comply with NSPS subpart GG.

1.3. New Source Review (“NSR”) Applicability

Because the St. Croix facility is a major stationary source, it is subject to the federal Prevention of Significant Deterioration (“PSD”) regulations codified in 40 Code of Federal Regulations (“CFR”) § 52.21.⁹ Under the preconstruction permitting provisions of the PSD program, a PSD permit is required if a project at an existing major source is a “major modification” as defined in 40 CFR § 52.21(b)(2).

Table 1-2 summarizes the results from the PSD applicability analysis performed for the MARPOL Project. This analysis has been performed using the calculation procedures prescribed by 40 CFR § 52.21(a)(2)(iv), consistent with the EPA guidance provided in Appendix D. The prescribed procedure is applied separately for each regulated PSD pollutant. Calculations are performed first for the project itself; if the total emissions increase from the project is less than the significant threshold for that pollutant, the project is not a major modification with respect to that pollutant, and contemporaneous netting calculations for that pollutant are not required. As presented in Table 1-2, the project emissions increase for each pollutant is less than the

⁸ These activities, by themselves, do not require approval to construct pursuant to the exemption for insignificant plant maintenance activities provided by Title V Operating Permit STX-TV-003-10 Attachment B. However, these activities are described herein for completeness because they are associated with the MARPOL Project and because they are considered in the emissions increase analysis discussed in Section 0 herein.

⁹ See footnote 1 herein. The federal nonattainment NSR program codified at 40 CFR § 52.24 is not applicable because the St. Croix facility is located in an area that is designated as unclassifiable or attainment with respect to all National Ambient Air Quality Standards. See, 40 CFR § 81.356.

Table 1-2. Summary of MARPOL Project Emissions Increase Calculation ¹⁰

	VOC	CO	NO _x	PM	PM ₁₀	PM _{2.5}	SO ₂	SAM
Baseline Actual Emissions (BAE)	2,998	1,931	3,496	217	205	206	877	36.3
Projected Actual Emissions (PAE)	2,048	1,613	3,446	40	127	125	491	35.1
Project Emissions Change	-950	-319	-51	-178	-78	-80	-386	-1.1
Significance Level	40	100	40	25	15	10	40	7
Subject to PSD Review	No	No	No	No	No	No	No	No

SAM: sulfuric acid mist

Note: PAE rates do not include the excludable emission increases.

significant level.¹¹ Thus, the results of the PSD applicability analysis indicate that the project is not subject to the PSD preconstruction permitting requirements.

Because preconstruction PSD permitting requirements are not applicable, only an Authority to Construct¹² (“ATC”) for the MARPOL Project is required prior to commencement of construction. The USVI DPNR has authority to issue these minor source permits under 12 VIRR § 206-20 and § 206-31.

1.4. Project Schedule

Construction activities are planned to commence upon permit issuance and to continue for approximately 18 months. Operation is planned to commence by January 1, 2020.

1.5. Document Overview

The contents of this document are organized as follows:

Section 1.0 provides an overview of the proposed project, a summary of the pollutant-by-pollutant emissions increases, and the project’s anticipated schedule.

Section 2.0 contains an overview of the work that will be performed as part of the MARPOL Project.

Section 3.0 contains an overview of all of the regulatory requirements that will result from the proposed project. This includes a description of both the USVI and federal requirements.

¹⁰ These values are based on preliminary calculations. To the extent required by 40 CFR § 52.21(r)(6)(i), Limetree Bay Terminals’s final calculations will be documented prior to beginning actual construction of the MARPOL Project.

¹¹ Per 40 CFR § 52.21(b)(49)(iii) because the MARPOL Project does not have an emissions increase of a regulated NSR pollutant that is significant, GHGs are not subject to regulation.

¹² This also encompasses the approvals required for the MARPOL Project under 12 VIRR §206-31.

Other Appendices to the MARPOL Project's permit application referenced herein include:

Appendix A – Area Map, Facility Plot Plan, and Process Flow Diagram

Appendix B – Detailed Emissions Increase Calculation

Appendix C – Draft Permit Conditions

Appendix D – Supporting Documents

2.0 Project Description

This section provides an overview of the refinery process units and utilities at the St. Croix facility within which work will be done (i.e., either alterations will be made or significant maintenance, repair, and component replacement activities will occur) as part of the proposed MARPOL Project. As noted above, maintenance and repair that is not a modification and is an insignificant Title V activity will also occur as part of the MARPOL Project. The section is organized by refinery process unit.

2.1. # 5 Crude Unit (#5 CDU)

The #5 CDU is used to fractionate crude and fuel oil components into different products for further processing. Historically, this process unit operated independently with a crude oil charge capacity of approximately 180,000 BPCD. As part of the MARPOL Project, piping will be installed to integrate certain vessels and other equipment from the #6 CDU (i.e., #6 CDU desalter and compressor) with the vessels and equipment at #5 CDU. The integrated equipment will operate as part of the #5 CDU, which will have a nominal crude oil charge capacity of 180,000 BPCD or less.

Heat exchangers are used to preheat crude upstream of the unit desalters which are used to remove salt and dirt from the crude oil raw material. Additional heat exchange then preheats the crude prior to the unit furnaces (H-3101A and H-3101B), which are used to vaporize the light portion of the feed. The crude fractionation column is then used to separate the feed into various fractions including overhead gasses, naphtha, kerosene, diesel, atmospheric gasoil, and atmospheric tower bottoms.

The overhead gases will be treated to remove hydrogen sulfide and used as fuel. The fractions including naphtha, kerosene, diesel and gas oil are desulfurized and either stored as products or further processed. Atmospheric tower bottoms are routed to #3 VAC, either via tankage or by direct transfer. Process wastewater and sour water are co-produced from the desalters and the overhead system of the crude tower and are treated in the wastewater plant or sour water strippers.

2.2. # 3 Vacuum Unit (#3 VAC)

The atmospheric tower bottoms from the #5 CDU tower are fed to #3 VAC where additional distillation steps take place under a vacuum. At #3 VAC, the feed is preheated in heat exchangers before it enters the Pre-Stripper Tower Fired Furnace H-4201. The Pre-Stripper operates under a slight vacuum provided by a single stage vacuum jet. Diesel and lighter products are removed at the Pre-Stripper Tower. From there the remaining heavier components are directed via the Vacuum Tower Fired Furnace H-4202 to the Vacuum Tower. The Light vacuum gas oil (“LVGO”) is routed to the #6 Distillate Desulfurizer (“#6 DD”) and the bottoms

stream from the Vacuum Tower (pitch) is then routed to the Delayed Coker Unit (“DCU”) for further processing.

As part of the MARPOL Project, the impeller in the vacuum booster pumps P-4234 A/B will be replaced with a larger pump impeller. This change will increase the capacity of these pumps. The DCU’s feed was previously supplied by multiple vacuum columns. Following the proposed MARPOL Project, #3 VAC will be the only process unit that supplies feed to the DCU. As a result, the capacity of the #3 VAC booster pumps P-4234 A/B must be increased to provide feed to the coker while running heavier crudes, which results in higher vacuum bottom rates.

2.3. #7 Distillate Desulfurizer (#7 DD)

Hydrodesulfurization is a catalytic chemical process used to remove sulfur from refined petroleum products, such as diesel fuel and fuel oils. The existing #7 DD is used to produce ultra low-sulfur diesel (“ULSD”) by removing sulfur from distillate. As part of the MARPOL Project, the ability to control the #7 DD reactor temperature will be improved by installing a packaged chiller on the compressor suction and a sulfur analyzer on the product line.

2.4. #3 Platformer (#3 Plat)

The #3 Plat is a catalytic reforming unit that uses a platinum catalyst in a chemical process. It is used to convert petroleum refinery naphthas (typically having low octane ratings) into high-octane liquid products called reformates to use as blend stocks to make high-octane gasoline. The reforming process converts low-octane linear hydrocarbons (paraffins) into branched alkanes (isoparaffins) and cyclic compounds. These compounds are then partially dehydrogenated (*i.e.*, stripped of some of their hydrogen) to produce high-octane aromatic hydrocarbons. The platinum based catalyst used in the reformer process is highly sensitive to poisoning by sulfur compounds, so a hydrodesulfurization section is placed ahead of the reforming process in the unit.

As part of the MARPOL Project, the Hydrobon section of #3 Plat will be used as a light naphtha desulfurization unit and the Reforming section will serve as an isomerization process. (Reforming and isomerization¹³ are alternative chemical reactions for producing high-octane gasoline blending components from naphtha streams.) To accomplish this new or replaced equipment in the process unit will include additional piping, replacement of reactor internals, retooling of the gas compressor, reactor charge pump changes, heat exchangers, and recycle gas driers.¹⁴

¹³ Isomerization is the process by which one molecule is transformed into another molecule which has exactly the same atoms (*e.g.*, the double bond is moved from one location to another.

¹⁴ For purposes of defining the emissions unit associated with these alterations the affected facility definition of process unit (*i.e.*, “means the components assembled and connected by pipes or ducts to process raw materials and

2.5. #6 Distillate Desulfurizer (#6 DD)

The existing #6 DD unit is designed to remove sulfur from a wide range of distillate streams. As part of the MARPOL Project, Limetree Bay Terminals will expand the use of this unit to cover removal of sulfur from vacuum gas oils to produce fuels compliant with the new MARPOL regulations. In order to optimize this unit for gas oil service, the following modifications will be made:

- Install piping and control valves to allow for the bypass of feed around each of the four sets of feed/effluent exchangers,
- Install an additional reactor effluent exchanger for preheating of feed from the low-pressure separator to the stripper,
- Install a hydrogen quench line to the reactors to provide for the additional temperature required to process heavy gas oils,
- Install on-line sulfur analyzers to allow the control of reactor temperatures based on product sulfur content.

2.6. #4 Platformer (#4 Plat)

The existing #4 Plat comprises the Hydrobon (hydrotreater) and a Platforming unit and is designed to process straight run naphtha from #5 CDU. It will continue to process a similar feed. As part of the MARPOL Project, the catalyst in #4 Plat will be replaced with a hydrotreating specific catalyst, chloride gas treaters will be installed to treat the net hydrogen from the high-pressure separator; and chloride liquid propane gas (“LPG”) treaters will be installed downstream of the naphtha stabilizer to treat the LPG product. Organic chlorides are known to be corrosive when combusted, so they are being removed to protect against corrosion in propane fired emissions units at the refinery.

2.7. Delayed Coker Unit (DCU)

The DCU processes the heavy pitch from the #3 VAC by thermally cracking the heavy molecules into lighter, more valuable products. The feed is preheated and mixed with recycle bottoms from the DCU Coker Main Fractionator prior to being fed to the DCU Heaters (H-8501A/B) and the Coke Drums (D-8501/2/3/4). The overhead material from the Coke Drums is quenched prior to entering the flash zone of the Coker Main Fractionator, which is operated at a slight vacuum.

The four Coke Drums are operated in a batch wise manner consisting of a charge period, depressurization period which occurs when the maximum depth of coke within drums is reached,

to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. . .”) in NSPS subpart GGG is used.

and a decoking period during which the coke deposits are removed. The coke which is removed exits the bottom of the Coke Drums and is transported from the Coke Pit to the coke piles in an enclosed conveyor system.

As part of the MARPOL Project the following changes are planned:

- Installation of a blowdown eductor system to meet the recently updated NESHAP subpart CC (*i.e.*, Refinery Sector Rule) requirement that Coke Drums vent to the atmosphere once the pressure in the drum reaches 2 psig.
- To improve the DCU's feed flexibility, a fuel oil feed system will be installed to support the feed of imported fuel oil including exchangers and a column nozzle. Imported fuel oil will be directed into the Coker Main Fractionator.
- Additional instrumentation will be installed in the Coke Drum deheading processes (*e.g.*, limit switches to indicate valve position and provide operators information related to which valves need to be opened and closed as part of the Coke Drum cycle processes).

2.8. Penex Unit

The existing Penex Unit comprises a hydrotreater followed by an isomerization unit and is designed to process light naphtha. As part of the MARPOL Project only the isomerization unit will resume operation. It will continue to process a hydrotreated light naphtha feed. Modifications to the existing fractionator stabilizers, reactor distributors, and piping and installation of additional heat exchangers are planned as part of the project.

2.9. #9 Distillate Desulfurizer (#9 DD)

Hydrodesulfurization is a catalytic chemical process used to remove sulfur from refined petroleum products, such as diesel fuel and fuel oils. As part of the MARPOL Project, the existing #9 DD will resume operation and be used to hydrotreat kerosene that is produced at the #5 CDU.

2.10. Boilers

Boilers #5, #8, #9, and #10 will be used to meet the steam requirements of the MARPOL Project. As part of the project, control technology (*e.g.*, low NO_x burners, SCR, etc.) that is needed to comply with applicable requirements of NSPS subpart D will be installed in #5, #8 and #9 Boilers.

2.11. Gas Turbines (GTs)

Gas turbines GT-7, GT-8, GT-9, GT-10, and GT-13 will be used to meet the electrical power requirements of the MARPOL Project as well as some part of the steam requirements. The gas

turbines will also continue to supply electricity for terminal operations and common utilities.¹⁵ As part of the project, SCR systems will be installed on GT-7 and GT-8 to comply with the applicable requirements of NSPS subpart GG.

2.12. Flares

Flares Nos. 3, 5 and 7, LPG Flare (STK 7921), Low-Pressure FCC Flare (“L.P. Flare - STK-7941”), and Ground Flare (“H.P. Flare – STK-7942”) will be used to support process unit operations following the proposed MARPOL Project. As part of the project, the flares will be brought into compliance with NSPS subpart Ja and the recently updated NESHAP subpart CC (*i.e.*, Refinery Sector Rule).

2.13. Tanks

Several of the existing tanks will be used to support operations following implementation of the MARPOL Project.

2.14. #2 Gas Recovery Unit (#2 GRU)

The #2 GRU combines many low-pressure off gases from different process units and compresses them prior to removing hydrogen sulfide (H₂S), so the cleaned gases can be used as compliant NSPS subpart J fuel gas (*i.e.*, fuel gas with a H₂S content that is less than 162 ppmv).

As part of the MARPOL Project a jumpover line will be installed to connect the gas from the product separator to the feed header for the feed gas knockout drum in the high-pressure amine contactor unit. The additional recontacting of refinery gas with amine will ensure compliance with the NSPS subpart J fuel gas H₂S standard.

2.15. Amine Units

Lean amine is used throughout the refinery to remove H₂S (*i.e.*, acid gas) from refinery process gases. The resulting rich amine is then regenerated by thermally removing the acid gas. The regenerated lean amine is then reused. As part of the MARPOL Project, changes will be made to the #4 and #5 Amine Units to comply with NSPS subpart J requirements and to #6 Amine Unit to allow it to support the operation of the East Sulfur Plant’s TGTU. #7 Amine Unit will resume operations but will not be altered.

At the #4 Amine Unit, the Rich Amine Flash Drum (D-4831) will be replaced with a larger drum and the #4 Amine unit Rich Amine Pumps (P-4837A/B) will be replaced or a third pump added to handle the increased flow to the No. 4 Amine Unit regenerator.

¹⁵ Limetree Bay Terminals is also required by the Operating Agreement to supply electricity to support remediation by the Environmental Response Trust on the former HOVENSA site.

As part of the East Sulfur Plants modified TGTU process, amine will be used to remove acid gas. To support the TGTU's operation, a tie-in connecting the TGTU to the #6 Amine Unit will be installed downstream of the Lean Amine Cooler. A new Rich Amine Pump will also be required at #6 Amine Unit. The amine that is used will change from 100% MEA (monoethanolamine) to a blend of approximately 40% MDEA (Methyl diethanolamine) in MEA.

2.16. East Sulfur Recovery Plant

The East Sulfur Recovery Plant ("SRP") currently comprises two Claus based sulfur recovery units (#3 and #4 SRUs), a Beavon Stretford Unit (#2 Beavon)¹⁶ TGTU, and a East Incinerator (H-4745), which was previously used to combust sulfur compounds in the #3 and #4 SRU tailgas when the #2 Beavon was being bypassed. As part of the MARPOL Project, the East SRP will be modified to increase its capacity to 365 long tons per day ("LTPD") and to ensure compliance with applicable NSPS subpart Ja SO₂ standard. To accomplish this at #3 SRU the thermal reactor air blowers will be replaced with blowers capable of a higher discharge pressure. To support the use of oxygen enrichment, the primary burner will be replaced with a high intensity burner containing an oxygen lance. The fired intra-stage reheaters will be replaced with steam reheaters, and catalyst will be reloaded into all reactor stages. At #4 SRU the thermal reactor air blowers will be replaced with blowers capable of a higher discharge pressure, to support the use of oxygen enrichment the primary burner will be replaced with a high intensity burner containing an oxygen lance, and catalyst will be reloaded into all reactor stages. Under the MARPOL Project, #2 Beavon will be converted to a Shell Claus Offgas Treater ("SCOT") type TGTU. To accomplish this, the catalyst in the hydrogenation reactor will be replaced and a TGTU steam reheater, quench column, absorber, pumps, and quench water cooler and filter system will be installed. Ductwork will be installed to direct the exhaust from the SCOT type TGTU to the existing East Incinerator (H-4745).

To comply with NSPS subpart Ja, a sulfur pit ejector system will be installed. This system will direct the sulfur vapors back to the front of the SRUs where they will be injected into the thermal reactor stage.

2.17. Sour Water Strippers

To process the sour water that results from refinery operations, No. 4 Sour Water Stripper ("#4 SWS") and #5 SWS will resume operation. Sour water tanks Tk-4725 and Tk-4726 have been dismantled. As a result, Tk-7443, which is an external floating roof tank, will return to service storing sour water.

¹⁶ No. 2 Beavon includes a fired reheater as part of its process equipment (H-4761). This heater will not be used in the MARPOL SRP configuration.

2.18. Advanced Wastewater Treatment Unit

The Advanced Wastewater Treatment Unit (“AWWTU”) processes wastewater from the facility and from remediation, and is currently in operation. However, some portions of the AWWTU will be returned to service as part of the MARPOL Project to comply with NESHAPs and TPDES requirements.

3.0 Air Regulatory Analysis

The applicability of federal and USVI air quality regulations to the proposed MARPOL Project is addressed in this Section. A review of the potentially applicable federal regulations including the Title V Operating Permit Program, PSD, NSPS, NESHAP, and Chemical Accident Prevention program is included in Sections 3.1 through 3.7. The applicability of USVI rules and regulations is discussed in Section 3.8.

Because the emissions units which are part of the proposed MARPOL Project are already permitted to operate, the Title V permit for Limetree Bay Terminals already contains compliance requirements for most of the applicable requirements discussed below. This will minimize the need for changes to the Title V permit.

3.1. Title V Operating Permit Program (40 CFR Part 70)

The Title V Operating Permit Program for the USVI is codified in 12 VIRR Chapter 9, Subchapter 206, Division 2, §§ 206-51 *et seq.*, and is administered by DPNR.

The St. Croix facility is an existing major source under the Title V Operating Permit Program. Limetree Bay Terminals is the owner and operator of the facility and holds Title V Air Permit No. STX-TV-003-10. A renewal application for this permit was timely filed and is pending with the DPNR. Consistent with prior guidance from DPNR, Limetree Bay Terminals is applying for an Authority to Construct and will subsequently apply for a Permit to Operate and/or modification of the Title V permit to incorporate the terms of the Authority to Construct in accordance with 12 VIRR §§ 206-21(b) and -82.

3.2. Federal NSR Permitting Applicability (40 CFR § 52.21)

As presented in Section 0, the proposed MARPOL Project is not a major modification and is not subject to federal PSD preconstruction permitting requirements. Limetree Bay Terminals has determined that there will be no significant emissions increases associated with the proposed MARPOL Project. A detailed presentation of the project emission increase calculation is included in Appendix B.

Limetree Bay Terminals will comply with applicable source obligation requirements specified in 40 CFR § 52.21(r)(6).

3.3. Federal Visibility Protection (40 CFR § 52.2781)

The federal implementation plan for visibility protection for Class I Air Areas at 40 CFR §52.2781 requires HOVENSA to notify EPA Region 2 sixty (60) days prior to “startup and resumption of operation of refinery process units at the HOVENSA, St. Croix, Virgin Islands facility.” Limetree Bay Terminals, LLC acquired the St. Croix, Virgin Islands refinery

from HOVENSA and will submit the notice required under 40 CFR §52.2781 to enable EPA to determine whether changes to the FIP are necessary to meet regional haze requirements (e.g. “reasonable further progress”).

3.4. New Source Performance Standards (40 CFR Part 60)

The federal New Source Performance Standards (“NSPS”) apply to newly constructed, modified, and reconstructed affected facilities in listed source categories. These rules are codified in various subparts of 40 CFR Part 60. As identified in Title V Air Permit No. STX-TV-003-10, certain boilers, gas turbines, fuel gas combustion devices, storage vessels, wastewater treatment facilities, sulfur recovery units, distillation and reaction processes and other equipment at the St. Croix facility are affected facilities under one or more NSPS rules.

Pursuant to 40 CFR §§ 60.2 and 60.14, except as provided by an exemption, a physical change or change in method of operation of an existing facility is a “modification” if the maximum achievable hourly emissions rate increases as a result of the change. The exemptions provided in the NSPS rules include increases in production rate achieved without a capital expenditure and routine maintenance, repair, and replacement (“RMRR”) activities.

The NSPS subparts potentially applicable to the emission units associated with the MARPOL Project are summarized in this Section. Any source subject to a NSPS is also subject to the general provisions of NSPS Subpart A.

3.4.1 NSPS Subpart A, General Provisions

NSPS subpart A includes the performance tests, performance evaluations (monitoring systems), notifications, recordkeeping, and reporting requirements. Limetree Bay Terminals will comply with the requirements specified in NSPS subpart A, as applicable.

3.4.2 NSPS Subpart J, Petroleum Refineries

NSPS subpart J applies to FCCU catalyst regenerators, fuel gas combustion devices, and Claus sulfur recovery plants which are located at petroleum refineries and which were most recently constructed, reconstructed, or modified between specified dates between 1973 and 2008. Any modification or reconstruction of an existing facility after these specified dates brings a facility within applicability of NSPS subpart J, discussed in Section 3.4.3 below, and has no effect on applicability of subpart J.

All fuel gas combustion devices at the St. Croix refinery which are already affected facilities under subpart J (e.g., certain GTs, heaters, and boilers), will remain affected facilities and will remain subject to the already applicable subpart J requirements; the MARPOL Project will have no effect on applicability.

3.4.3 NSPS Subpart Ja, Petroleum Refineries

NSPS subpart Ja applies to FCCUs, fluid coking units, delayed coking units, fuel gas combustion devices (including process heaters), flares, and sulfur recovery plants which are located at petroleum refineries and which are constructed, reconstructed, or modified after specified dates in 2007-2008. The East Sulfur Recovery Plant is currently subject to the requirements of NSPS subpart Ja. As part of the MARPOL Project, the DCU and the fuel gas combustion devices (i.e., process heaters, boilers, and gas turbines) will not be modified¹⁷ or reconstructed.¹⁸ As a result, these facilities will not become subject to the NSPS subpart Ja requirements. Pursuant to 40 CFR § 60.100a(c)(1), modifications to Flares 3, 5, 7 and the L.P. Flare-STK-7941 and H.P. Flare-STK-7942 are anticipated as part of the MARPOL Project.¹⁹ As a result, at the time of each modification, each given flare will become subject to the requirements of NSPS subpart Ja.

All fuel gas combustion devices at the St. Croix refinery which are already affected facilities under subpart Ja (e.g., certain GTs, heaters, and boilers), will remain affected facilities and will remain subject to the already applicable subpart Ja requirements; the MARPOL Project will have no effect on applicability.

3.4.4 NSPS Subpart GG, Stationary Gas Turbines

NSPS subpart GG applies to stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr based on the lower heating value of the fuel fired, and that commenced construction, modification, or reconstruction after October 3, 1977 and before February 18, 2005 (trigger date for NSPS KKKK, refer to Section 3.4.7). Pursuant to the Title V permit, GTs 1 through 10 are affected facilities under NSPS subpart GG.

3.4.5 NSPS Subpart GGG – Petroleum Refinery Equipment Leaks

Subpart GGG applies to affected facilities in petroleum refineries for which construction, reconstruction, or modification commenced after January 4, 1983 and on or before November 7, 2006. Affected facilities under NSPS GGG include compressors and all equipment in a process unit. Equipment is defined in 40 CFR § 60.591 as each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in volatile organic compound (“VOC”) service. All of the work planned as part of the MARPOL Project will occur after November 7, 2006, as a result it is not possible to trigger the requirements of NSPS subpart GGG.

¹⁷ See definition of modification at 40 CFR § 60.14.

¹⁸ The FCCU and some of the sources fuel gas combustion devices are not resuming operation as part of the MARPOL Project and thus are not modified or reconstructed.

¹⁹ Confirmation of this assumption will be made and notification will be provided to the VIDPNR in accordance with the NSPS subpart A notification requirement (40 CFR § 60.7).

3.4.6 NSPS Subpart GGGa – Petroleum Refinery Equipment Leaks

NSPS subpart GGGa applies to affected facilities in petroleum refineries for which construction, reconstruction or modification commenced after November 7, 2006. Affected facilities under NSPS subpart GGGa include compressors and all equipment in a process unit. Equipment is defined in 40 CFR § 60.591a as each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.²⁰

As described in Section 2.0, as part of the MARPOL Project there will be addition or replacement of equipment within existing process units. For purposes of this application, the equipment additions or replacements that are planned are presently assumed to require a capital expenditure.²¹ As a result, the process units resuming operation as part of the MARPOL Project that may trigger the requirements of NSPS subpart GGGa include:

- #5 CDU
- #3 VAC
- #7 DD
- #3 Plat
- #6 DD
- #4 Plat
- DCU
- Penex
- #2 GRU
- #4, #5, #6, and #7 Amine Units

3.4.7 NSPS Subpart QQQ, Petroleum Refinery Wastewater Systems

NSPS Subpart QQQ applies to affected facilities located in petroleum refineries for which construction, modification, or reconstruction is commenced after May 4, 1987. Affected facilities include:

- individual drain systems,
- oil-water separators, and
- aggregate facilities.

²⁰ In VOC service means that the piece of equipment contains or contacts a process fluid that is at least ten (10) percent VOC by weight.

²¹ NSPS GGGa cross references a test for what constitutes a capital expenditure (see 40 CFR 60.590a(c). Confirmation of this assumption will be made and notification will be provided to the USVI DPNR and EPA in accordance with the NSPS subpart A notification requirement (40 CFR § 60.7).

Any new/modified individual drain systems associated with the MARPOL Project are affected facilities as described at 40 CFR 60.690(a)(4) and will be subject to the requirements of NSPS subpart QQQ.²²

3.4.8 NSPS Subpart KKKK, Stationary Gas Turbines

NSPS Subpart KKKK applies to stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr based on the higher heating value of the fuel fired, and that commenced construction, modification, or reconstruction after February 18, 2005.

GT-7 and GT-8 will be retrofitted with SCR to comply with the applicable NSPS subpart GG NO_x standard. Per 40 CFR § 60.14(e)(5), the addition of air pollution control equipment does not constitute a modification under 40 CFR Part 60. In addition, the installation of an SCR does not meet the 40 CFR § 60.15 definition of a reconstruction because pollution control equipment is not part of the NSPS affected facility. Thus, installation of the SCR does not trigger NSPS Subpart KKKK.

GT-13 was constructed after the effective date of subpart KKKK and is subject to the requirements of this standard. None of the other existing facilities will be modified or reconstructed as part of the MARPOL Project.

3.5. Emissions Standards For Hazardous Air Pollutants (40 CFR Part 61)

The pre-1990 federal National Emissions Standards for Hazardous Air Pollutants (“NESHAP”) rules in 40 CFR part 61 apply to listed sources of certain hazardous air pollutants (“HAP”). The NESHAP subparts potentially applicable to the emission units associated with the proposed permit application are summarized in this Section. Any source subject to a NESHAP is also subject to the general provisions of NESHAP subpart A.

3.5.1 NESHAP Subpart A, General Provisions

Subpart A to the NESHAP standards includes the notification, recordkeeping, monitoring, performance testing, and control device requirements. Limetree Bay Terminals will continue to comply with these requirements as applicable.

3.5.2 NESHAP Subpart M, Asbestos

NESHAP Subpart M applies to asbestos-containing material in pipe insulation, roofing, siding, or other materials to be modified or demolished prior to the modification activities. The

²² Individual drain system means all process drains connected to the first common downstream junction box. The term includes all such drains and common junction box, together with their associated sewer lines and other junction boxes, down to the receiving oil-water separator.

proposed MARPOL project could require the removal or disturbance of asbestos-containing materials. Limetree Bay Terminals will comply with this regulation should it become applicable.

3.5.3 NESHAP Subpart FF, Benzene Waste Operations

NESHAP subpart FF applies to facilities used for treatment or storage of benzene-containing wastes at petroleum refineries. Limetree Bay Terminals will continue to comply with these requirements as applicable.

3.6. Emissions Standards For Hazardous Air Pollutants For Source Categories (40 CFR Part 63)

The NESHAP rules in Part 63 (a/k/a Maximum Achievable Control Technology (“MACT”) standards) apply to HAP sources that are major sources in specifically regulated industrial source categories. The MACT rules apply to new, modified, reconstructed, and existing affected facilities that must meet the requirements as specified in the applicable provisions. These requirements vary depending on whether the facility is existing, new, or reconstructed. The MACT subparts potentially applicable to the emission units associated with the proposed permit application are summarized in this Section. Any source subject to a MACT is also subject to the general provisions of MACT Subpart A.

3.6.1 MACT Subpart A, General Provisions

Subpart A to the NESHAP MACT standards includes notification, recordkeeping, monitoring, performance testing, and control device requirements. Limetree Bay Terminals will comply with these requirements as applicable.

3.6.2 MACT Subpart CC, Petroleum Refineries

MACT subpart CC applies to petroleum refining process units and related emission points that are:

- located at a major source of HAPs, as defined in section 112(a) of the Clean Air Act; and
- emit or have equipment containing or contacting one or more of the HAPs listed in Table 1 of 40 CFR Part 63 subpart CC.

The Limetree Bay Terminals Title V permit includes MACT subpart CC provisions as applicable requirements for all affected sources. In general, where associated with a petroleum refining process unit or otherwise included in § 63.640(c), MACT subpart CC requires control of HAPs emissions from the following:

- miscellaneous process vents²³,
- storage vessels,
- wastewater streams and treatment operations,
- equipment leaks from pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation system “in organic hazardous air pollutant service”²⁴,
- gasoline loading racks,
- marine vessel loading operations, and
- heat exchange systems used to transfer heat from process fluids to water without intentional direct contact of the process fluid with the water (i.e., non-contact heat exchanger) and to transport and/or cool the water in a closed-loop recirculation system (cooling tower system) or a once-through system (e.g., river or pond water).²⁵

As previously noted, the West Refinery was idled in early 2011 and the East Refinery was idled in early 2012. In June 2014, EPA proposed what is known as the Refinery Sector Rule (“RSR”). The final rule was published in the Federal Register on December 1, 2015, with an effective date of February 1, 2016. This final rule is based on a risk and technology review of two pre-existing refinery emissions standards: the MACT subpart CC, and the NESHAP for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (MACT subpart UUU). The RSR update to subpart CC includes updated requirements for the following emissions sources:

- Delayed Coking Units,
- Miscellaneous Process Vents (“MPVs”), including maintenance vents,
- Flares as control devices,
- Storage tanks,
- Fugitive equipment leaks (through fence line monitoring), and
- Marine loading.

As part of the MARPOL Project, any actions needed to ensure compliance with the current MACT subpart CC requirements (*i.e.*, those requirements included in the December 2015 final rule) will be implemented.

²³ Miscellaneous process vent means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit. Miscellaneous process vents include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere.

²⁴ In organic hazardous air pollutant service or in organic HAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least five (5) percent by weight of total organic HAP listed in Table 1 of subpart CC.

²⁵ For closed-loop recirculation systems, the heat exchange system consists of a cooling tower, all petroleum refinery process unit heat exchangers that are in organic HAP service serviced by that cooling tower, and all water lines to and from these petroleum refinery process unit heat exchangers.

3.6.3 MACT Subpart WW, NESHAP for Storage Vessels (Tanks)—Control Level 2

MACT Subpart WW is applicable to the control of air emissions from storage vessels for which another subpart references the use of this subpart for such air emission control. The RSR rule references Subpart WW for air emissions control. As discussed in Section 3.6.2, Limetree Bay Terminals will take any actions needed to ensure compliance with the RSR rule and will comply with the cross referenced standards in Subpart WW as part of compliance with the RSR rule.

3.6.4 MACT Subpart UUU, NESHAP for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

MACT Subpart UUU is applicable to:

- FCCU catalyst regeneration flue gas vent,
- Catalytic reforming unit (“CRU”) catalyst regeneration flue gas vents and vents that are used during the unit depressurization, purging, coke burn, and catalyst rejuvenation,
- Sulfur recovery plant unit vents or the tail gas treatment units serving sulfur recovery plants, that are associated with sulfur recovery, and
- Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit.

As noted above, an update of NESHAP subpart UUU was codified in December 2015. The RSR update to subpart UUU includes updated requirements for the following affected sources:

- CRUs,
- FCCUs, and
- Sulfur Recovery Units

As part of the MARPOL Project, any actions needed to ensure compliance with the revised MACT subpart UUU requirements will be implemented.

3.6.5 MACT Subpart EEEE, Organic Liquids Distribution (Non-Gasoline)

MACT subpart EEEE establishes national emission limitations, operating limits, and work practice standards for organic HAP emitted from organic liquids distribution (“OLD”) (non-gasoline) operations at major sources of HAP emissions. This standard also establishes requirements to demonstrate initial and continuous compliance with the emission limitations, operating limits, and work practice standards. OLD operation means the combination of activities and equipment used to store or transfer organic liquids into, out of, or within a plant site regardless of the specific activity being performed. Activities include, but are not limited to, storage, transfer, blending, compounding, and packaging. Organic liquids include crude oils downstream of the first point of custody transfer, but do not include the following liquids: gasoline (including aviation gasoline), kerosene (No. 1 distillate oil), diesel (No. 2 distillate oil), asphalt, and heavier distillate oils and fuel oils.

Per the Title V permit, existing tanks TK-1204, TK-1205, TK-8001, TK-8002, are subject to the requirements of MACT subpart EEEE. None of these tanks will be used as part of the MARPOL Project and none of the tanks are affected by the project are expected to be constructed or reconstructed. As a result, no additional tanks are expected to become subject to the requirements of the MACT subpart EEE standards.

3.6.6 MACT Subpart YYYY, NESHAP for Stationary Combustion Turbines

MACT subpart YYYY establishes national emission limitations and operating limitations for HAP emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations. Stationary combustion turbines which commenced construction or reconstruction on or before January 14, 2003 are “existing stationary combustion turbines” [40 CFR § 63.6090(a)(1)]. A stationary combustion turbine is new if construction of the unit commenced after January 14, 2003 [40 CFR § 63.6090(a)(2)].

GT-7 and GT-8, were installed prior to January 14, 2003 and the proposed retrofit does not constitute reconstruction as the term is defined in § 63.2, therefore, GT-7 and GT-8 are existing stationary combustion turbines under MACT subpart YYYY. Pursuant to 40 CFR § 60.6090(b)(4) existing stationary combustion turbines do not have to meet the requirements of MACT Subpart YYYY and of Subpart A. GT-13 was constructed after the effective date of MACT subpart YYYY and is subject to the requirements of this standard. None of the other existing sources (*i.e.*, GT-9 and GT-10) will be modified or reconstructed as part of the MARPOL Project.

3.6.7 MACT Subpart ZZZZ, NESHAP for Stationary Reciprocating Internal Combustion Engines

MACT Subpart ZZZZ establishes national emission limitations and operating limitations for HAPs emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

An affected source must meet the requirements of 40 CFR Part 60 Subpart IIII, for compression ignition engines. The existing RICE used to drive the Penex Unit’s compressors are subject to the applicable requirements of MACT subpart ZZZZ. Limetree Bay Terminals will continue to comply with the provisions of 40 CFR 63 Subpart ZZZZ.

3.6.8 MACT Subpart DDDDD, NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

MACT Subpart DDDDD is applicable to the following new, reconstructed, and existing affected sources:

- All existing industrial, commercial, and institutional boilers and process heaters; and
- New or reconstructed industrial, commercial, or institutional boiler or process heater, located at a major source.²⁶

As previously noted no boiler or process heater will be modified or reconstructed as part of the MARPOL Project. The MARPOL Project will result in the firing of gaseous fuels in the affected boilers and process heaters.²⁷ As a result, because the existing boilers and process heaters are greater in size than 10 MMBtu/hr they will be subject to the MACT subpart DDDDD Table 2 requirements for gas-fired sources.

As previously noted, the West Refinery was idled in early 2011 and the East Refinery was idled in early 2012. MACT DDDDD did not impose substantive requirements on the facility until after that date. As part of the MARPOL Project, any actions needed to ensure compliance with the current MACT subpart DDDDD requirements will be implemented and relevant changes proposed to the Title V permit.

3.7. 40 CFR 68 – Chemical Accident Prevention

The provisions of 40 CFR Part 68 [also known as Section 112(r)] apply to stationary sources having more than a threshold quantity of a regulated substance in a process. In general, Part 68 requires that covered facilities develop and implement a risk management program and maintain documentation of the program at the site. The risk management program includes an analysis of the potential offsite consequences of an accidental release, a five-year accident history, a release prevention program, and an emergency response program. Covered facilities also must develop and submit a risk management plan (“RMP”), which includes registration information, to EPA no later than June 21, 1999, or the date on which the facility first has more than a threshold quantity in a process, whichever is later. Covered facilities also must continue to implement the risk management program and update their RMPs periodically or when processes change, as required by the rule. Limetree Bay Terminals has a RMP which reflects the idled status of the refinery process units. Limetree Bay Terminals will review the facility RMP and update it based on the resumed operation of the refinery process units and support utilities and changes made as a result of the MARPOL Project.

²⁶ A boiler or process heater is new if it commences construction after June 4, 2010; reconstructed if it meets criteria at 40 CFR 63.2; and existing if it is not new or reconstructed.

²⁷ Oil firing in the heaters and boilers is not included in the MARPOL Project Scope.

3.8. USVI Air Quality Control Regulations

New, modified, or reconstructed sources are also subject to Title 12, Chapter 9 of the USVI Air Pollution Control Act. Potential applicability of the emission units associated with the proposed permit application are summarized in this Section.

3.8.1 § 204-22 Visible Air Contaminants

This rule establishes the following opacity provisions:

- Opacity from any stationary source is limited to 20 percent for any time period [§ 204-22(a)].
- Opacity from fuel-burning facilities is limited to 40 percent for a period aggregating no more than 3 minutes in any 30 minutes [§ 204-22(b)].
- Opacity from any moored or docked vessel is limited to 20% at any time except from fuel-burning facilities. Opacity from fuel-burning facilities on moored vessels is limited to 40 percent at any time period [§204-22(c)].

Limetree Bay Terminals will continue to comply with the opacity provisions of § 204-22(a) and (b) by complying with opacity requirements already stipulated in the facility Title V Operating Permit. §204-22(c) does not apply to the facility.

3.8.2 § 204-23 Particulate Matter Emissions

This rule establishes particulate matter emission limits from hot-mix asphalt plants [§ 204-23(a)], fuel-burning equipment [§ 204-23(b)], incinerators [§ 204-23(c)], and industrial process equipment [§ 204-23(d)].

Title V permit conditions already stipulate the allowable particulate matter emission rate for each applicable source that will comply with these provisions.

3.8.3 § 204-24 Storage of Petroleum or Other Volatile Products

Section §204-24 requires that any stationary tank of more than 65,000 gallons capacity that is used for the storage of any commodity with a vapor pressure of 2 pounds per square inch absolute (“psia”) or higher at actual storage conditions, be equipped with a floating roof [§ 204-24(a)], a vapor recovery system [§ 204-24(b)], or other equipment of equivalent efficiency to control the emissions of VOC [§ 204-24(c)].

The proposed MARPOL Project will require the use of both existing floating roof tanks and fixed roof tanks. Fixed roof tanks will be used for the storage of commodities with low vapor pressure (less than 2.0 psia) at actual tank conditions, and are therefore exempt from the requirements in §204-24. Floating roof tanks will be used for the storage of high vapor pressure commodities (above 2.0 psia). The sources Title V Permit No. STX TV-003-10 already contains

a provision requiring compliance with 204-24(a). Limetree Bay Terminals will continue to comply with these requirements as applicable.

3.8.4 § 204-25 Fugitive Emissions

This rule requires the operational control of particulate matter from buildings, appurtenances, and roads to prevent particulate from becoming airborne. The Title V permit already contains a provision requiring compliance where this regulation applies. Limetree Bay Terminals will apply the necessary measures, as described in Section § 204-25(a)(1) through (9) to ensure compliance with the provisions of Section §204-25(a) through (f) as applicable.

3.8.5 § 204-26 Sulfur Compounds Emission Control

This rule relates to sulfur compound emission control. The Title V permit already contains a provision requiring compliance where this regulation applies. Limetree Bay Terminals will continue to comply with the maximum ground level SO₂ concentration and ambient air H₂S concentrations as required by § 204-26(a)(1) and § 204-26(b).

3.8.6 § 204-28 Internal Combustion Engine Limits

This rule establishes the following opacity provisions:

- Opacity from any mobile sources is limited to 20 percent for a period of time equal to one minute [§ 204-28(a)]
- Opacity from any stationary source is limited to 20 percent for any time period except during startup [§ 204-28(b)(i)].
- Opacity from any stationary source is limited during periods of startup to 40 percent [§ 204-28(b)(ii)]

Limetree Bay Terminals will continue to comply with the opacity provisions of § 204-22(a) and (b) by complying with opacity requirements already stipulated in the facility Title V Operating Permit.

3.8.7 § 204-45 Standards of Performance for Sulfur Recovery Units at Petroleum Refineries.

This provision applies to the tail gas treatment system at Hess oil Virgin Islands Corporation (“HOVIC”), predecessor to HOVENSA. It is included as part of the Virgin Islands State Implementation Plan to ensure that the operation of the refinery would not cause or contribute to a violation of the SO₂ National Ambient Air Quality Standard (“NAAQS”). The standard requires venting of tail gas from sulfur recovery units to a Beavon TGTU.²⁸ However, Beavon

²⁸ Beavon Units emit reduced sulfur compound emissions (*i.e.*, hydrogen sulfide, carbonyl sulfide, and carbon disulfide), not SO₂.

units require periodic maintenance which requires them to be shut down. During periods of Beavon unit shut down, this rule allows tail gas to be vented to an incinerator to oxidize the reduced sulfur compounds to SO₂. The rule allows up to 30 days per year of incineration and up to 30 tons per day of SO₂ emissions and requires residual oil fired sources to switch to a fuel oil with a sulfur content of 0.5% (or less) during such periods.

As discussed in Section 2.16, as part of the MARPOL Project, Limetree Bay Terminals is upgrading the existing Beavon #2 to a SCOT type TGTU, which will be more reliable and more effective at reducing sulfur compound emissions. Limetree Bay Terminals believes § 204-45 is not applicable to the new configuration. However, the SCOT type TGTU will enable Limetree to meet the substantive SO₂ and H₂S requirements of this rule by:

- Venting all tail gas from the sulfur recovery units to the SCOT type TGTU, except during malfunctions of the TGTU.
- Eliminating the venting of tail gas to incinerators during periodic TGTU maintenance, which allowed up to 720 hours of incineration versus a projected 168 hours of incinerator use with the SCOT type TGTU, which will reduce overall SO₂ emissions.
- Virtually eliminating H₂S emissions.
- Installation of a certified SO₂ continuous emissions monitoring system (“CEMS”).

To the extent possible given the fact that only one TGTU will be in operation as a result of the MARPOL Project and that unit will be a different design than specified in the rule, Limetree Bay Terminals will comply with § 204-45.

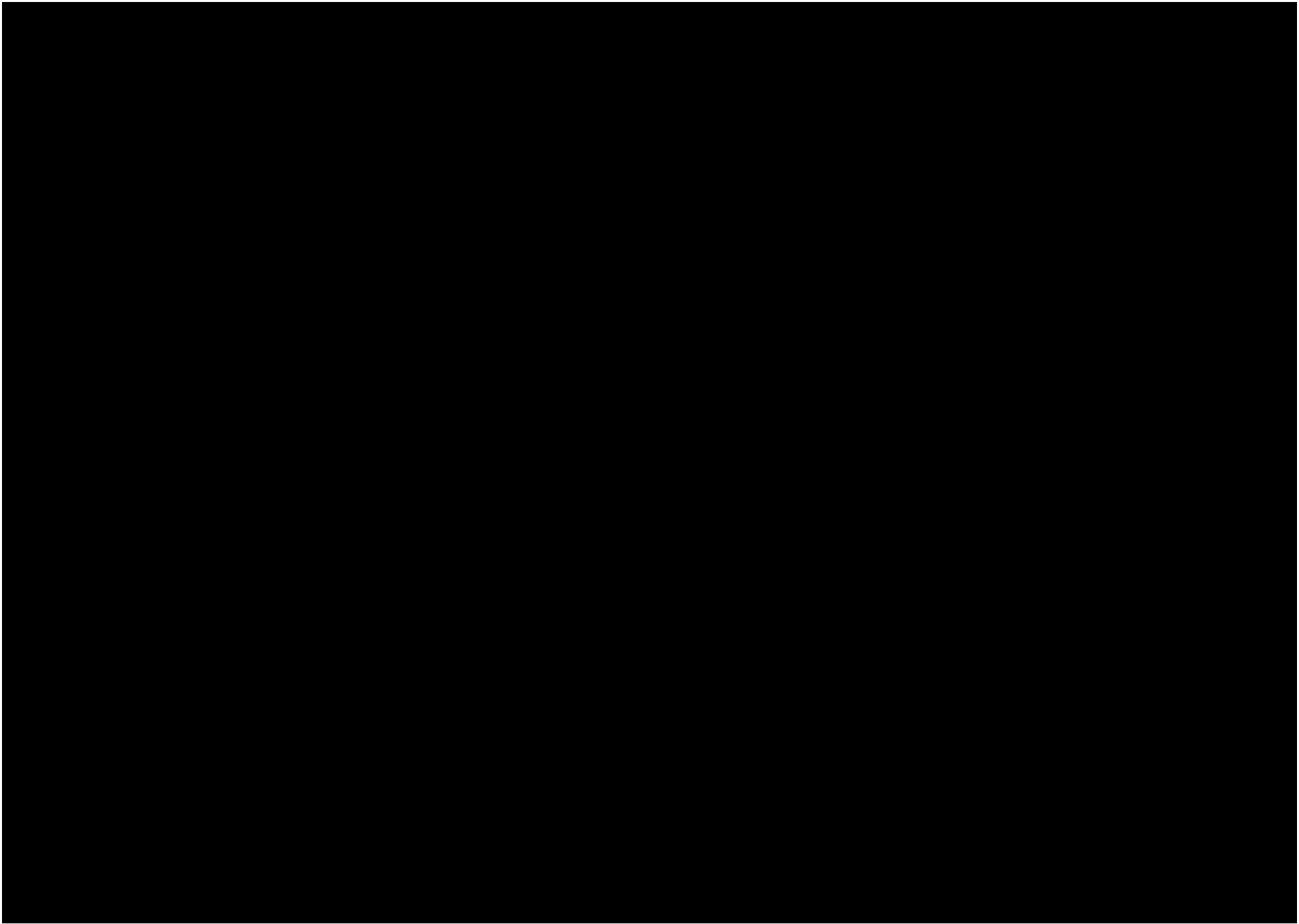
Appendix A – Figures

Figure A-1 Area Map

Figure A-2 Facility Plot Plan Showing Location of
Modified/Affected Process Units

Figure A-3 MARPOL Project Process Flow

Figure A-1: AREA MAP



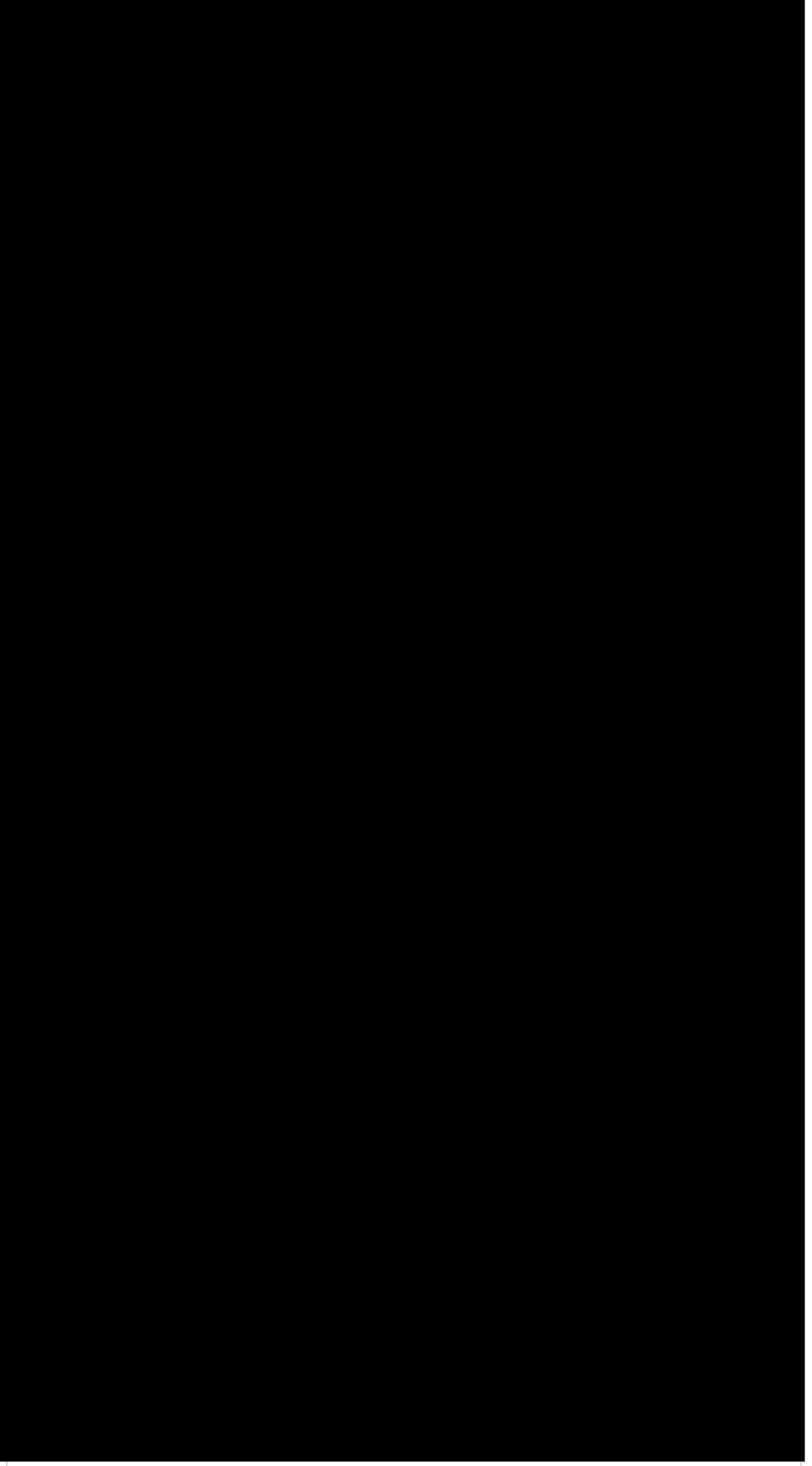
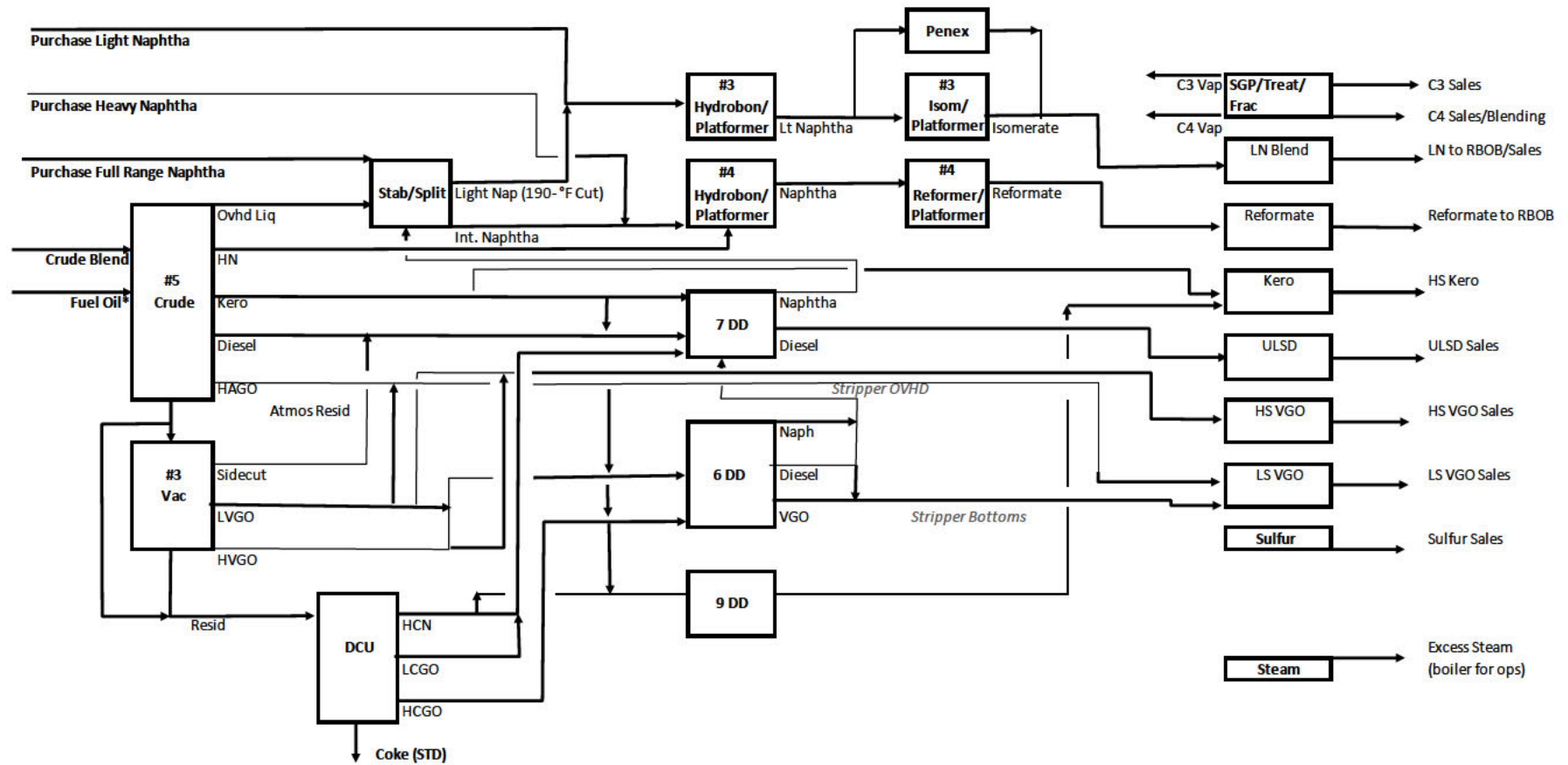


Figure A-3. MARPOL Project Process Flow



Appendix B

Project Emissions Increase Calculation

Appendix B Project Emissions Increase Calculation

The St. Croix facility is a major stationary source for purposes of the federal Prevention of Significant Deterioration (“PSD”) preconstruction permitting program.¹ The facility is located in an area currently classified as attainment or unclassifiable for all criteria pollutants.²

Because the facility is an existing major stationary source, to determine if the proposed MARPOL Project is a “major modification,” the emissions increase calculation was performed in accordance with the applicability procedures at 40 CFR § 52.21(a)(2). More specifically, because the MARPOL Project will involve only existing emissions units (i.e., units that have existed for more than two (2) years from the date such emissions unit first operated³), the actual-to-projected-actual (“ATPA”) applicability test for projects that only involve existing emissions units was used to determine if the project will result in a significant emissions increase of a regulated NSR pollutant (i.e., Consistent with the EPA guidance provided in Appendix D, the differences between the projected actual emissions and the baseline actual emissions on a unit-by-unit basis were summed).⁴

The ATPA test computes the difference between projected actual emissions (“PAE”) from each existing emissions unit following completion of the project and baseline actual emissions (“BAE”) in any consecutive 24-month period selected from ten years prior to submittal of a complete permit application for the project. Only one baseline period may be used for each pollutant and the same baseline period must be used for all of the project’s potentially affected emissions units for a given pollutant.

B.1 PSD Applicability Summary

Table 1 summarizes the results from the PSD applicability analysis for the proposed MARPOL Project. As shown, the analysis indicates PSD review is not applicable to the proposed project. To determine the PSD applicability of a proposed action the excludable portion of the projected actual emissions has not been quantified because it is unrelated to the project and is not needed to determine PSD applicability. If excludable emissions are used in the PSD applicability analysis they affect requirements of 40 CFR § 52.21(r)(6). Limetree Bay Terminals/Limetree Bay Refining Operating will comply with applicable source obligation requirements specified in 40 CFR § 52.21(r)(6) to the extent they are triggered.

¹ See, 40 CFR § 52.21. This federal rule is applicable in the Virgin Islands pursuant to 40 CFR § 52.2779.

² See, 40 CFR § 81.356.

³ See, 40 CFR § 52.21(b)(7)(i) and (ii).

⁴ See, 40 CFR § 52.21(a)(2)(iv)(c).

Table 1. Summary of MARPOL Project Emissions Increases⁵

	VOC	CO	NO _x	PM	PM ₁₀	PM _{2.5}	SO ₂	SAM
Baseline Actual Emissions (BAE)	2,998	1,931	3,496	217	205	206	877	36.3
Projected Actual Emissions (PAE)	2,048	1,613	3,446	40	127	125	491	35.1
Project Emissions Change	-950	-319	-51	-178	-78	-80	-386	-1.1
Significance Level	40	100	40	25	15	10	40	7
Subject to PSD Review	No	No	No	No	No	No	No	No

SAM: sulfuric acid mist

Note: PAE rates do not include the excludable emission increases.

The contents of this appendix include the information required by the pre-project recordkeeping requirements at 40 CFR § 52.21(r)(6)(i). The following sections of this appendix provide a description of the project and its affected emissions units and present the underlying basis for the calculation of BAE and PAE, for each of the emissions units affected by the MARPOL project.⁶

For purposes of presentation this appendix is organized as follows:

B.2 MARPOL Project Overview

B.3 Actual-to-Projected Actual Emissions Increase Analysis

B.3.1 Baseline Actual Emissions

B.3.2 Projected Actual Emissions

B.2 MARPOL Project Overview

The St. Croix facility is a complex, integrated petroleum refinery consisting of refinery process units and various supporting operations including sulfur recovery plants, steam and electric power generation via boilers and gas turbine cogeneration units, wastewater treatment, and a marine terminal. As of 2010, the refinery's crude oil nameplate processing rate was approximately 500,000 barrels per calendar day ("BPCD"), including generally smaller equipment on the west side of the facility ("West Side") and generally larger equipment on the east side of the facility ("East Side"). Many of the refinery process units were idled on the West Side in early 2011, reducing the refinery's crude charge rate to approximately 350,000 BPCD, and all of the operations refining units, primarily on the East Side, were idled in early 2012. The

⁵ These values are based on preliminary calculations. To the extent required by 40 CFR § 52.21(r)(6)(i), Limetree Bay Terminals, LLC's/Limetree Bay Refining Operating, LLC's final calculations will be documented prior to beginning actual construction of the MARPOL Project.

⁶ As previously noted, to determine the applicability of the PSD preconstruction permitting requirements the excludable emissions do not need to be quantified. As a result, this analysis does not quantify the excludable emissions.

refinery process units that will resume operation as part of the MARPOL Project are generally among the larger East Side units that remained operational until 2012.

The scope of work for the MARPOL Project is summarized in Table 2. The projected emissions following the proposed MARPOL Project are based on expected utilization rates, which are in part based on historical operation of the units by HOVENSA and projected operating rates after completion of the MARPOL Project.

B.3 Actual-to-Projected Actual Emissions Increase Analysis

In circumstances where there is reasonable possibility, as defined in 40 CFR 52.21(r)(6)(vi), per the source obligation requirement at 40 CFR § 52.21(r)(6)(i), before beginning actual construction on a project, a record shall be maintained that identifies the emissions units whose emissions could be affected by the project. The existing emissions units that could be affected by the proposed project are summarized in Table 2.

Existing units are also subject to certain downward adjustments to address any periods of non-compliance as well as any emissions limitations with which the unit must currently comply. For the analysis presented herein, the following downward adjustments were made:

- SO₂ BAE for the fuel gas combustion devices were adjusted downward in accordance with NSPS subparts J SO₂ standards.
- SO₂ BAE for the East Sulfur Recovery Plant was adjusted downward in accordance with NSPS subpart Ja requirement.
- NO_x BAE for GT-7 and GT-8 were adjusted downward, in accordance with the NSPS subpart GG standard.
- NO_x BAE emissions for #5 Boiler, #8 Boiler, and #9 Boiler were adjusted in accordance with the NSPS Subpart D requirement.
- VOC, PM/PM₁₀/PM_{2.5}, and SO₂ BAE emissions for the Coker Vent were adjusted in accordance with 40 CFR Part 60, Subpart CC.
- VOC BAE for the Marine Loading was adjusted in accordance with the 98 percent capture efficiency and destruction efficiency requirement during gasoline/gasoline blend stock marine loading.⁷

No other downward adjustments to the BAE were needed.

⁷ See Permit Number: STX-895-AC-P0-16.

Table 2. High-Level Summary of the MARPOL Project Scope

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ⁸	Overview of Proposed Modifications ⁹
#5 Crude Unit (#5 CDU)	- Heater H-3101A - Heater H-3101B - #5 CDU Process Unit (fugitives)	- Affected - Affected - Modified	- None - None - Install tie-ins from #5 CDU to #6 CDU desalter - Install tie-ins from #5 CDU to #6 CDU overhead compressor
#3 Vacuum Unit (#3 VAC)	- Heater H-4201 - Heater H-4202 - #3 VAC Process Unit (fugitives)	- Affected - Affected - Modified	- None - None - Replace impeller in the vacuum booster pumps (P-4234 A/B)
#7 Distillate Desulfurizer (#7 DD)	- Heater H-4301A - Heater H-4301B - Heater H-4302 - #7 DD Process Unit (fugitives)	- Affected - Affected - Affected - Modified	- None - None - None - Install packaged chiller on compressor suction - Install on-line sulfur analyzer on reactor rundown
#3 Platformer (#3 Plat)	- Heater H-4401 - Heater H-4402 - #3 Plat Process Unit (fugitives)	- Affected - Affected - Modified	- None - None - Repurpose #3 Plat hydrobon section to a light naphtha hydrotreater and #3 Plat reformer to isomerization unit - Install new reactor charge pumps, reactor feed / effluent heat exchangers, reactor charge heat exchanger, recycle gas dryer regeneration feed / effluent heat exchanger, recycle gas dryer regeneration cooler and recycle gas driers

⁸ Additional analysis may result in an update to the status of the listed affected emissions units with regards to possible changes that are required.

⁹ The modifications that are summarized are based on the current definition of the project. Additional changes within a given process unit may be identified as part of the detailed design work. The Marpol Project will result in work being performed on affected units, but that work is not expected to be a modification.

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ⁸	Overview of Proposed Modifications ⁹
#6 Distillate Desulfurizer (#6 DD)	<ul style="list-style-type: none"> - Heater H-4601A - Heater H-4601B - Heater H-4602 - Compressor C-4601A - Compressor C-4601B - Compressor C-4601C - #6 DD Process Unit (fugitives) 	<ul style="list-style-type: none"> - Affected - Affected - Affected - Affected - Affected - Affected - Affected - Modified 	<ul style="list-style-type: none"> - None - None - None - None - None - None - None - Install piping and control valves to allow for feed bypass around inlet exchangers - Install additional effluent exchanger - Install hydrogen quench line into reactors - Install on-line sulfur analyzer on reactor rundown
#4 Platformer (#4 Plat)	<ul style="list-style-type: none"> - Heater H-5401 - Heater H-5402 - Heater H-5451 - Heater H-5452 - Heater H-5453 - Heater H-5454 - Heater H-5455 - #4 Plat Process Fugitives 	<ul style="list-style-type: none"> - Affected - Affected - Affected - Affected - Affected - Affected - Affected - Affected - Modified 	<ul style="list-style-type: none"> - None - None - None - None - None - None - None - None - Use #4 Plat Hydrobon section as a naphtha hydrotreater; use #4 Plat reformer section as a naphtha reformer - Install chloride gas treaters - Install chloride LPG treaters
Delayed Coker Unit (DCU)	<ul style="list-style-type: none"> - Heater H-8501A - Heater H-8501B - DCU Vent - DCU Process Fugitives 	<ul style="list-style-type: none"> - Affected - Affected - Affected - Modified 	<ul style="list-style-type: none"> - None - None - None - Install fuel oil feed system - Install blowdown eductor system (to comply with 40 CFR Part 60, Subpart CC) (2 psi vent target) - Install additional instrumentation to support coke drum deheading process

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ⁸	Overview of Proposed Modifications ⁹
Penex Unit	- Heater H-202 - Compressor C-200A - Compressor C-200B - Compressor C-200C - Penex Process Fugitives	- Affected - Affected - Affected - Affected - Modified	- None - None - None - None - Install additional heat exchange - Modify fractionator stabilizers, - Modify reactor distributors
#9 Distillate Desulfurizer (#9 DD)	- Heater H-5301A - Heater H-5301B - Heater H-5302 - #9 DD Process Fugitives	- Affected - Affected - Affected - Affected	- None - None - None - None
Boilers	- #5 Boiler (B-1155) - #8 Boiler (B-3303) - #9 Boiler (B-3304) - #10 Boiler (B-3701)	- Modified - Modified - Modified - Affected	- Install NO _x control technology (e.g., low NO _x burners or Selective Catalytic Reduction (“SCR”)) as needed to comply with NSPS subpart D - Install NO _x control technology (e.g., low NO _x burners or Selective Catalytic Reduction (“SCR”)) as needed to comply with NSPS subpart D - Install NO _x control technology as needed to comply with NSPS subpart D - None
Powerhouse 2 - Gas Turbine/Steam Generators	- GT No. 7 (G-3407) ¹⁰ - GT No. 8 (G-3408) ¹⁰ - GT No. 9 (G-3409) - GT No. 10 (G-3410) - GT No. 13 (G-3413)	- Modified - Modified - Affected - Affected - Affected	- Install SCR to comply with NSPS subpart GG - Install SCR to comply with NSPS subpart GG - None - None - None
Flares	- Flare 3 - Flare 5 - Flare 7 ¹⁰ - LPG Flare - Low-Pressure FCC Flare - Ground Flare	- Affected - Affected - Affected - Affected - Affected - Affected	- None - None - None - None - None - None

¹⁰ An emissions unit that is currently in operation and is not resuming operation.

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ⁸	Overview of Proposed Modifications ⁹
Tanks	- Multiple ¹¹	- Affected	- Tanks
# 2 Gas Recovery Unit (#2 GRU)	- #2 GRU Process Fugitives	- Modified	- Install jumpover connecting the product separator to the feed gas knockout drum at the high-pressure amine contactor
Amine Units	- Gas Treatment (Unit No. 4800 #4 Amine Unit) - Gas Treatment (Unit No. 5800 #5 Amine Unit) - #6 Amine Unit - #7 Amine Unit	- Modified - Modified - Modified - Affected	- Replace #4/5 Amine Unit flash drum with larger drum and replace #4/5 Amine Unit rich amine pump (P-4837 A/B) or install a third pump to comply with NSPS subpart J - Install tie-in from TGTU to #6 Amine Unit - Install rich amine pump at #6 Amine Unit - None
East Sulfur Recovery Plant	- #3 & 4 SRU / #2 Beavon/East Incinerator / Sulfur pits	- Modified	- #3 SRU: Replace air blowers (higher discharge pressure), primary burner (high intensity/oxygen lance to support oxygen enrichment), intra-stage reheaters (steam reheaters), and reloading of catalyst (all reactors) - #4 SRU: Replace air blowers (higher discharge pressure), primary burner (high intensity/oxygen lance to support oxygen enrichment), and reloading of catalyst (all reactors) - #2 Beavon: Convert tailgas treating unit ("TGTU") to a Shell Claus Offgas Treater ("SCOT") type TGTU by changing the hydrogenation reactor catalyst, replace fired TGTU reheater with steam reheater, install quench column, absorber, pumps, and quench water cooler and filter system - Install sulfur pit eductor system to transport pit vapors from sulfur pits to SRU thermal reactor

¹¹ Some tanks are currently in operation, others may need repair prior to return to service.

Refinery Process Unit	Source ID(s)/ Emissions Unit	Modified/Affected Unit ⁸	Overview of Proposed Modifications ⁹
East Sulfur Storage Area	- East Sulfur Storage Area	- Affected	- None
Sulfur Storage & Ship Loading	- Sulfur storage & Ship Loading	- Affected	- None
Coke Handling	- Coke handling, storage, and loading system	- Affected	- None
Advance Wastewater Treatment System	- Advanced Wastewater Treatment System ¹² - #4 Sour Water Stripper (“SWS”) - #5 SWS	- Affected - Affected - Affected	- None - None - None
Marine Loading	- Marine Loading ¹¹	- Affected	- None

¹² An emissions unit that is currently in operation, portions of which may be resuming operation.

B.3.1 Baseline Actual Emissions

The BAE rates for the affected emissions units are presented in Table 3 (combustion units, *i.e.*, process heaters, boilers, gas turbines, and reciprocating engines) and Table 4 (combustion unit totals, flares, and non-combustion units).

Combustion Units (Process Heaters, Boilers, Gas Turbines, and Reciprocating Engines)

The BAE estimates for the affected process heaters, boilers, gas turbines, and reciprocating engines were determined based on the following historical records:

NO_x: Fuel usage data (oil & gaseous fuel), unit-specific stack test based emission factors where available for gaseous fuel firing, and EPA AP-42 emission factors for oil firing. Where available, NO_x CEMS data.

SO₂: Fuel usage data (oil and gaseous fuel); for fuel oil firing, sulfur content data and EPA AP-42 emission factor; for gaseous fuel firing, NSPS subpart J H₂S monitoring data and fuel gas TRS data.

CO, PM, PM₁₀, PM_{2.5}, and VOC: Fuel use data (oil & gaseous fuel) and pollutant specific EPA AP-42 emission factors or, where available, unit-specific stack test based emission factors. Where available, CO CEMS data.

H₂SO₄ mist (“SAM”): SO₂/SO₃ ratio based on EPA AP-42, Chapter 1.3, Table 1.3-1.

The BAE estimates for other sources of emissions were determined based on the following historical records:

Flares

NO_x and CO: Flare specific header flowrate data, flare gas characteristic data, and EPA AP-42 Chapter 13, Table 13.5-1 emission factors.

SO₂: Flare specific header flowrate data, flare gas characteristic data, and NSPS subpart Ja standard, and incident reporting data.

PM, PM₁₀, and PM_{2.5}: Flare specific header flowrate data, flare gas characteristic data, and AP-42, Chapter 1.4, Table 1.4-2.

VOC: Flare specific header flowrate data, flare gas characteristic data, and 98 percent destruction efficiency.

H₂SO₄ mist (“SAM”): SO₂/SO₃ ratio based on EPA AP-42, Chapter 1.3, Table 1.3-1.

East Sulfur Recovery Plant

East Incinerator NO_x: Fuel use data and EPA AP-42 factor.

East Incinerator SO₂: Incident reporting data and fuel use and NSPS subpart J H₂S monitoring data and fuel gas TRS data.

East Incinerator CO, PM, PM₁₀, PM_{2.5}, and VOC: Fuel use data and pollutant specific EPA AP-42 factors.

East Incinerator SAM: SO₂/SO₃ ratio based on EPA AP-42, Table 1.3-1.

#2 Beavon PM/PM₁₀: Cooling water circulation rate, demister pad efficiency, total dissolved solids content.

Tanks

VOC: The BAE emissions rates for the project affected tanks were determined using the EPA AP-42 Chapter 7.1 Organic Liquid Storage Tanks equations and actual information related to the affected tanks design, materials stored in the tank, and annual throughput, and where applicable, roof landings.

Coker Drum Vents

VOC, CO, PM/PM₁₀/PM_{2.5}, SO₂, and H₂S: Stack test based algorithms and Coker operating parameter data.

Coke Handling

PM/PM₁₀/PM_{2.5}: Based on coke handling and shipment rate data and EPA AP-42 emission factors.

Marine Loading

VOC: Product throughput data and EPA AP-42 emission factors.

Process Fugitives

VOC: The BAE rates for the component related VOC emissions are based on component counts and services along with historical equipment leak inspection data and emission factors from EPA's AP-42, EPA's 1995 "Protocol for Equipment Leak Emissions Estimates," and American Petroleum Institute's (API) 1996 Air Quality Workshop presentation on heavy liquid emission factors.

Wastewater Treatment

VOC: The BAE emissions rates from the wastewater treatment plant were determined using EPA's Water 9 Model.

Sulfur Storage and Loading

PM/PM₁₀/PM_{2.5}: Sulfur loading rate data and EPA AP-42 emission factor.

B.3.2 Projected Actual Emissions

The PAE for the affected emissions units are presented in Table 5 (combustion units *i.e.*, process heaters, boilers, gas turbine, and reciprocating engines) and in Table 6 (combustion unit totals, fares, and non-combustion units). A summary level roll-up of the project's emissions increases is presented in Table 7.

For existing emissions units whose emissions could be affected by a project, PAE are defined, in part, as:

[T]he maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project,...¹³

For an existing emissions unit, the definition of PAE includes the following additional provision:

[T]he owner or operator ... [s]hall exclude, in calculating any increase in emissions that results from [t]he particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth.^{14,15}

For the emission units that have been idled and will resume operation as part of the MARPOL Project, no portion of the PAE is excludable, as all emissions increases are assumed to be related to the project. The only emissions units for which excluded emissions could be accounted for, are those units that were not idled and which continued to operate in support of the terminal operations at the St. Croix facility. The excludable part of the projected actual increases would be a function of the business activity for the terminal. However, as previously noted, the contribution of excludable emissions to the PAE does not require quantification in order to determine the applicability of the PSD preconstruction permitting requirements. As a result, for purposes of this application, the excludable part of the projected actual emissions has not been determined.

The basis for the PAE from those existing emissions units that could be affected by the MARPOL Project are provided below.

¹³ See 40 CFR § 52.21(b)(41)(i).

¹⁴ See 40 CFR § 52.21(b)(41)(ii)(c).

¹⁵ For convenience, these emissions are referred to as "excluded emissions."

The PAE for each of the existing emissions units that will resume operation as part of the MARPOL Project was determined as follows:

Heaters & Boilers: The PAE for all pollutants were determined using projected fuel use rates for each process unit which will resume operation. Projected fuel use rates are based on a combination of process knowledge, projected unit rates, and historic HOVENSA fuel use data for that process unit. For all pollutants except SO₂/SAM, the same unit specific emission factors that were used to determine the BAE were used to determine the PAE because no change in the unit specific emissions factors for these pollutants is expected to result from the project.

Gas Turbines (GTs): Projected electrical requirements (i.e., kw) developed on a process unit-by-process unit basis, plus data for ongoing terminal operations, were used to determine a projection of the facility's overall electrical demand. A GT sparing philosophy that allows one GT to trip off-line while leaving enough remaining generating capacity to catch the MARPOL Project's load was then used to determine an annual mean generating capacity. The GT efficiency that corresponds to the mean capacity was then used to determine an annual fuel usage rate. This rate and the BAE emissions factors after any required downward adjustment were then used to determine the PAE rates. The projected NO_x was based on the applicable NSPS subpart GG NO_x standard except for GT-13 which is subject to NSPS subpart KKKK. As noted above, no changes in the unit specific emissions factors used to determine the BAE are expected to result from the project.

Flares: To determine the PAE rates from the flares, a flaring rate per crude throughput factor was applied to historical flare gas composition data and because no change in the emissions factors are expected due to the MARPOL Project the same emission factors were used.

Sulfur Recovery Plant (SRP): To comply with the NSPS subpart Ja requirements, the existing #2 Beavon Stretford tailgas treating unit ("TGTU") used to control TRS emissions from # 3 & 4 SRUs will be replaced with a SCOT type TGTU followed by the existing East Incinerator (H-4745). To determine the PAE rates from the SRP, the projected sulfur load was used in combination with known SCOT type TGTU design information and prior upset data to project emissions associated with unit upsets.

Tanks: To determine the PAE from the MARPOL Project's affected tanks, EPA's AP- 42 Chapter 7.1 Organic Liquid Storage Tanks equations were used along with the project's projected throughput rates, material storage characteristics (e.g., storage temperature, total vapor pressure, vapor density), and tank type.¹⁶ To account for emissions due to landing losses, historical data was used to project the future frequency and expected rates of emissions.

¹⁶ See <https://www3.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf>.

Coker Vent: To determine the PAE, the historical rate of emissions was adjusted proportionately with the projected Coker rate following the MARPOL Project.

Coke Handling: To determine the PAE, the historical rate of emissions was adjusted proportionately with the projected Coker rate following the MARPOL Project.

Marine Loading: To determine the PAE, the projected production rates of the future product slate was used along with EPA AP-42 emissions factors. For gasoline/gasoline blend stock loading a 98 percent capture efficiency was applied and the captured vapors related combustion emissions from the thermal oxidizer (H-1612) were determined.

Process Fugitives: To determine the PAE, updated component counts and services were used along with historical equipment leak inspection data and emissions factors from EPA's AP-42, EPA's 1995 "Protocol for Equipment Leak Emissions Estimates," and American Petroleum Institute's (API) 1996 Air Quality Workshop presentation on heavy liquid emission factors.

Wastewater Treatment: To determine the PAE, the projected wastewater production rate due to the MARPOL Project was used along with EPA's Water 9 Model.

Sulfur Storage and Loading: To determine the PAE, the historical rate of emissions was adjusted proportionately with the projected sulfur production rate following the MARPOL Project.

Table 3. Summary of Baseline Actual Emissions Combustion Units - Average 2009-2010

Source Code	Unit Description	Project Affected Unit Y/N	Baseline Actual Emissions							
			VOC	CO	NOx ^{a,b}	PM ^c	PM10 ^d	PM2.5 ^d	SO2	SAM ^{g,h}
			tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
H-202	PENEX	Y	1.2	18.0	60.0	0.4	1.6	1.6	1.6	0.1
C-200A	PENEX	Y	0.6	29.7	3.9	0.18	0.36	0.4	0.0	0.0
C-200B	PENEX	Y	0.6	31.6	1.9	0.18	0.36	0.4	0.0	0.0
C-200C	PENEX	Y	0.6	16.7	1.8	0.18	0.36	0.4	0.0	0.0
H-3101A	5 CDU	Y	3.7	50.2	198.7	7.9	12.5	12.5	67.3	3.0
H-3101B	5 CDU	Y	4.1	55.7	219.5	8.5	13.5	13.5	72.7	3.2
H-4201	3 VAC	Y	2.3	29.2	125.4	6.7	9.7	9.7	57.6	2.6
H-4202	3 VAC	Y	2.0	24.5	110.0	6.6	9.4	9.4	57.2	2.5
H-4301A	7 DD	Y	0.7	11.3	13.5	0.3	1.0	1.0	1.2	0.0
H-4301B	7 DD	Y	0.8	11.8	14.1	0.3	1.1	1.1	1.3	0.0
H-4302	7 DD	Y	1.4	21.7	26.9	0.5	2.0	2.0	3.2	0.1
H-4401	3 PLATFORMER	Y	1.4	21.1	33.3	0.5	1.9	1.9	3.9	0.2
H-4402	3 PLATFORMER	Y	1.0	14.9	49.5	0.3	1.3	1.3	1.9	0.1
H-4455	3 PLATFORMER	Y	1.5	22.2	24.2	0.5	2.0	2.0	4.1	0.2
H-4601A	6 DD	Y	0.4	6.3	7.5	0.1	0.6	0.6	0.9	0.0
H-4601B	6 DD	Y	0.4	6.3	7.5	0.1	0.6	0.6	0.9	0.0
H-4602	6 DD	Y	0.9	13.8	17.9	0.3	1.2	1.2	1.9	0.1
C-4601A	6 DD	Y	2.6	12.0	77.6	0.0	0.2	0.2	0.0	0.0
C-4601B	6 DD	Y	2.6	12.0	74.8	0.0	0.2	0.2	0.0	0.0
C-4601C	6 DD	Y	2.6	12.0	69.9	0.0	0.2	0.2	0.0	0.0
H-5301A	9 DD	Y	0.6	9.7	11.6	0.2	0.9	0.9	1.3	0.0
H-5301B	9 DD	Y	0.6	9.3	11.0	0.2	0.8	0.8	1.2	0.0
H-5302	9 DD	Y	1.7	25.9	37.1	0.6	2.3	2.3	5.0	0.2
H-5401	4 PLATFORMER	Y	1.3	20.3	30.2	0.5	1.8	1.8	3.6	0.2
H-5402	4 PLATFORMER	Y	0.9	14.1	47.0	0.3	1.3	1.3	1.7	0.1
H-5451	4 PLATFORMER	Y	2.8	42.4	73.1	1.0	3.8	3.8	6.6	0.3
H-5452	4 PLATFORMER	Y	2.5	38.0	65.5	0.9	3.4	3.4	6.7	0.3
H-5453	4 PLATFORMER	Y	1.8	27.9	48.1	0.6	2.5	2.5	4.4	0.2
H-5454	4 PLATFORMER	Y	0.7	10.1	10.9	0.2	0.9	0.9	1.3	0.0
H-5455	4 PLATFORMER	Y	1.4	20.9	20.6	0.5	1.9	1.9	3.7	0.2
H-8501A	COKER	Y	0.5	2.2	18.9	0.8	2.2	2.2	5.4	0.2

Table 3. Summary of Baseline Actual Emissions Combustion Units - Average 2009-2010

Source Code	Unit Description	Project Affected Unit Y/N	Baseline Actual Emissions							
			VOC	CO	NOx ^{a,b}	PM ^c	PM10 ^d	PM2.5 ^d	SO2	SAM ^{g,h}
			tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
H-8501B	COKER	Y	0.2	1.4	20.9	0.8	2.2	2.2	5.4	0.2
H-4745	3 & 4 SRU ^e	Y	0.2	2.9	9.8	0.1	0.3	0.3	167.5	2.9
H-4761	2 Beavon	Y	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0
#5 Boiler (B-1155)		Y	3.4	43.2	149.2	9.9	14.4	14.4	82.6	3.7
#8 Boiler (B-3303)		Y	4.9	61.4	212.4	14.2	20.7	20.7	123.4	5.5
#9 Boiler (B-3304)		Y	3.9	48.9	172.1	11.9	17.1	17.1	102.8	4.6
#10 Boiler (B-3701)		Y	2.1	23.6	27.2	0.6	2.2	2.2	0.3	0.0
GT No. 7 (G-3407)	16 MW	Y	2.1	82.0	660.1	2.4	8.0	8.0	11.0	0.5
GT No. 8 (G-3408)	16 MW	Y	1.0	37.1	360.8	1.4	4.5	4.5	7.2	0.3
GT No. 9 (G-3409)	21 MW	Y	2.4	15.0	79.5	2.3	6.6	6.6	11.0	0.5
GT No. 10 (G-3410)	24 MW	Y	1.9	15.0	88.0	2.1	6.9	6.9	9.0	0.4
GT No. 13 (G-3413)	25 MW	Y	3.2	7.4	27.6	5.7	18.6	18.6	14.3	0.6
BAE w/o SRUs (H-4745) / 2 Beavon (H-4761)			71.0	976.8	3,310	90	183	183	683	30

Notes:

- a NOx emissions for units that fired a combination of fuel gas and 6 oil, emissions based on AP-42 factors are used in lieu of test data due to potential difference between fuel mix ratios from testing.
- b NOx emissions from gas turbines downwardly adjusted in accordance with NSPS subpart GG. Boiler 8 & 9 NOx emissions adjusted in accordance with NSPS subpart D.
- c 2009 emissions inventory estimates for PM are adjusted to exclude the condensable particulates in accordance with EPA guidance. See 77 FR 65107.
- d 2009 emissions inventory estimates for PM10 and PM2.5 are adjusted to include the condensable particulates in accordance with EPA guidance. See 77 FR 65107. Values pulled from calculation for PM/PM10 inventory which includes condensables.
- e For the purposes of this analysis, East Incinerator is assumed to have no contribution to the SO2 baseline emissions after applying J/Ja limit of 250 ppm SO2.
- g Combustion sources < 100 MMBtu/h 0.017 SO2 converted to SAM. AP-42 Table 1.3-1 ratio SO3/SO2 * (98 H2SO4/80 SO3)
- h Combustion sources > 100 MMBtu/h 0.044 SO2 converted to SAM. AP-42 Table 1.3-1 ratio SO3/SO2 * (98 H2SO4/80 SO3)

Table 4. Summary of Baseline Actual Emissions

	Baseline Actual Emissions (tpy)							
	VOC	CO	NOx	PM	PM10	PM2.5	SO2	H ₂ SO ₄ mist
Process Type								
Combustion Total (process heaters, boilers, gas turbines, engines)	71	977	3,310	90	183	183	683	30.2
Coker Drum Vents	8	1		2			1	0.1
Coke Handling				4	2	1		
3 & 4 SRU (H-4745) / 2 Beavon (H-4761)	0.2	2.9	11.7	0.1	0.3	0.3	167.5	2.9
Sulfur Pits Vents				0.03	0.03	0.03		
Beavon 2 Cooling Tower	7			116	0.2	0		
Sulfur Storage and Loading	11							
Flares	1,973	951	175	5	19	21	25	3.1
Tanks								
Tanks (Storage)	448.4							
Marine Loading	89							
Process								
Process Fugitives - Monitored	38.4							
Process Fugitives - Unmonitored	56							
Waste Water Treatment	296							
Total BAE (tpy)	2,998	1,931	3,496	217	205	206	877	36.3

Table 5. Summary of Projected Actual Emissions Combustion Units

Source Code	Unit Description	Project Affected Unit Y/N	Unit Size Fuel Gas		Distillate/6-oil	Summary of TPY Emissions ^{a,b,e}							
						VOC	CO	NOx	PM	PM10	PM2.5	SO2	SAM ^{g,h}
			mmBtu/hr	mmBtu/yr	mmBtu/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
H-202	ISOM H-202	Y	122	428,362	0	1.2	17.6	58.8	0.4	1.6	1.6	6.7	0.30
C-200A	ISOM Recips	Y	9	22,776	0	0.3	22.1	1.4	0.1	0.2	0.0	0.0	0.00
C-200B	ISOM Recips	Y	9	22,776	0	0.3	19.8	0.5	0.1	0.2	0.0	0.0	0.00
C-200C	ISOM Recips	Y	9	22,776	0	0.3	16.5	1.0	0.1	0.2	0.0	0.0	0.00
H-3101A	CDU5	Y	381	2,100,126	0	5.7	86.5	288.3	2.0	7.8	7.8	26.9	1.20
H-3101B	CDU5	Y	381	2,100,126	0	5.7	86.5	288.3	2.0	7.8	7.8	26.9	1.20
H-4201	Vac3	Y	253	1,239,148	0	3.3	51.0	170.1	1.2	4.6	4.6	15.9	0.71
H-4202	Vac3	Y	245	1,198,954	0	3.2	49.4	164.6	1.1	4.5	4.5	15.4	0.68
H-4301A	DHT	Y	67	231,508	0	0.6	9.5	11.3	0.2	0.9	0.9	3.0	0.05
H-4301B	DHT	Y	67	231,508	0	0.6	9.5	11.3	0.2	0.9	0.9	3.0	0.05
H-4302	DHT	Y	122	423,160	0	1.1	17.4	22.2	0.4	1.6	1.6	5.4	0.24
H-4401	LNHT	Y	134	109,449	0	0.3	4.5	7.1	0.1	0.4	0.4	1.4	0.06
H-4402	LNHT	Y	128	104,226	0	0.3	4.3	14.3	0.1	0.4	0.4	1.3	0.06
H-4455	LNHT	Y	138	112,877	0	0.3	4.6	5.1	0.1	0.4	0.4	1.4	0.06
H-4601A	GOHT	Y	61	249,850	0	0.7	10.3	12.2	0.2	0.9	0.9	3.2	0.06
H-4601B	GOHT	Y	61	249,850	0	0.7	10.3	12.2	0.2	0.9	0.9	3.2	0.06
H-4602	GOHT	Y	119	486,249	0	1.3	20.0	26.3	0.5	1.8	1.8	6.2	0.28
C-4601A	GOHT-C	Y	21	170,327	0	10.0	47.4	305.6	0.0	0.9	0.9	0.1	0.00
C-4601B	GOHT-C	Y	21	170,327	0	10.0	47.4	294.8	0.0	0.9	0.9	0.1	0.00
C-4601C	GOHT-C	Y	21	170,327	0	10.0	47.4	275.5	0.0	0.9	0.9	0.1	0.00
H-5301A	KHT (DD9)	Y	67	103,339	0	0.3	4.3	5.1	0.1	0.4	0.4	1.3	0.02
H-5301B	KHT (DD9)	Y	67	103,339	0	0.3	4.3	5.1	0.1	0.4	0.4	1.3	0.02
H-5302	KHT (DD9)	Y	122	188,888	0	0.5	7.8	14.0	0.2	0.7	0.7	2.4	0.11
H-5401	NHT	Y	134	342,128	0	0.9	14.1	21.0	0.3	1.3	1.3	4.4	0.19
H-5402	NHT	Y	128	325,799	0	0.9	13.4	44.7	0.3	1.2	1.2	4.2	0.19
H-5451	Ref	Y	381	2,092,041	0	5.6	86.1	153.8	1.9	7.8	7.8	26.8	1.19
H-5452	Ref	Y	248	1,361,914	0	3.7	56.1	100.1	1.3	5.1	5.1	17.4	0.78
H-5453	Ref	Y	248	1,361,914	0	3.7	56.1	100.1	1.3	5.1	5.1	17.4	0.78
H-5454	Ref	Y	77	424,122	0	1.1	17.5	31.2	0.4	1.6	1.6	5.4	0.09
H-5455	NHT	Y	138	352,843	0	1.0	14.5	21.3	0.3	1.3	1.3	4.5	0.20
H-8501A	DCU	Y	200	1,653,603	0	0.8	2.9	15.7	0.7	2.9	2.9	17.6	0.78
H-8501B	DCU	Y	200	1,653,603	0	0.3	1.8	14.9	0.7	2.9	2.9	17.6	0.78
H-4745	0.0	Y	55.00	481,800	0	1.3	19.8	19.3	0.4	1.8	1.8	233.3	4.02
H-4761	0.0	Y	10.00	87,600	0	0.0	0.0	3.9	0.0	0.0	0.0	0.0	0.00
#5 Boiler (B-1155)	West Side Process Boile	Y	539.20	700,800	0	1.9	28.9	70.1	0.7	2.6	2.6	10.9	0.48
#8 Boiler (B-3303)	Process Boilers	Y	511.90	370,034	0	1.0	15.2	37.0	0.3	1.4	1.4	4.7	0.21
#9 Boiler (B-3304)	Process Boilers	Y	511.90	374,370	0	1.0	15.4	37.4	0.3	1.4	1.4	4.8	0.21
#10 Boiler (B-3701)	Process Boilers	Y	225.00	192,917	0	0.5	5.1	26.5	0.1	0.4	0.4	2.5	0.11
GT No. 7 (G-3407)	Gas Turbine/Steam Gen	Y	317.00	1,059,590	55,768	1.1	43.5	332.0	1.1	3.8	3.8	8.3	0.37
GT No. 8 (G-3408)	Gas Turbine/Steam Gen	Y	392.40	1,411,601	74,295	1.5	58.0	92.7	1.5	5.1	5.1	11.1	0.49

Table 5. Summary of Projected Actual Emissions Combustion Units

Source Code	Unit Description	Project Affected Unit Y/N	Unit Size Fuel Gas		Distillate/6-oil	Summary of TPY Emissions ^{a,b,e}							
						VOC	CO	NOx	PM	PM10	PM2.5	SO2	SAM ^{g,h}
			mmBtu/hr	mmBtu/yr	mmBtu/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
GT No. 9 (G-3409)	Gas Turbine/Steam Gen	Y	304.00	1,532,159	80,640	1.6	10.3	100.5	1.6	5.5	5.5	12.0	0.54
GT No. 10 (G-3410)	Gas Turbine/Steam Gen	Y	325 ⁽⁵⁾	1,353,369	71,230	1.4	12.0	99.5	1.4	4.9	4.9	10.6	0.47
GT No. 13 (G-3413)	Gas Turbine/Steam Gen	Y	626.00	2,809,113	147,848	3.0	18.7	38.7	3.0	10.2	10.2	7.9	0.35
Total						89.5	1,088	3,356	27	105	105	547	17
PAE w/o SRUs (H-4745) / 2 Beavon (H-4761)						88.2	1,068	3,332	27	104	103	313	13

Footnotes

- a NOx emissions for boilers that fired a combination of fuel gas and 6 oil, emissions based on AP-42 factors are used in lieu of test data due to potential difference between fuel mix ratios from testing.
- b NOx emissions from gas turbines downwardly adjusted in accordance with NSPS subpart GG. See NSPS GG NOx Limits GT 7 & 8 tab for derivation of emission factors. NOx emissions for boilers based on NSPS subpart D standard for gaseous fuels.
- c reserved
- d reserved
- e For the purposes of this analysis, East Incinerator emissions are based on NSPS subpart Ja limit of 250 ppm SO2 with 7 day TGTU bypass.
- f reserved
- g Combustion sources < 100 MMBtu/hr 0.017 SO2 converted to SAM. AP-4: 0.017 SO2 converted to SAM. AP-42 Table 1.3-1 ratio SO3/SO2 * (98 H2SO4/80 SO3)
- h Combustion sources > 100 MMBtu/hr 0.044 SO2 converted to SAM. AP-4: 0.044 SO2 converted to SAM. AP-42 Table 1.3-1 ratio SO3/SO2 * (98 H2SO4/80 SO3)

Table 6. Projected Actual Emissions

	Projected Actual Emissions (tpy)							
	VOC	CO	NOx	PM	PM10	PM2.5	SO2	SAM
Process Type								
Combustion Total (process heaters, boilers, gas turbines, engines)	88	1,068	3,332	27	104	103	313	13.4
Coke Drum Vent	11	1.0		3			1.0	0
Coke Handling & Storage				5	2	2		
3 & 4 SRU	0.8	12	14	3	10	10	163	19.9
Sulfur Pits ¹				0	0	0		
Beavon 2 Cooling Tower	Replaced by TGTU/Incin							
Sulfur Storage and Loading	17			0				
Flares	1043	530	97	2.7	10.7	10.7	14.0	1.7
Tanks								
Storage	659							
Marine Loading	6	2	2	0.06	0.19	0.19	0.06	0
Process								
Process Fugitives - Monitored	38							
Process Fugitives - Unmonitored	57							
Waste Water Treatment	128							
Total PAE (tpy)	2,048	1,613	3,446	40	127	125	491	35.1

1 - Assumed pitted vapors are recirculated to the SRU

Table 7. Project Emissions Increases

	ATPA (tpy)							
	VOC	CO	NOx	PM	PM10	PM2.5	SO2	SAM
Process Type								
Combustion Total (process heaters, boilers, gas turbines, engines)	17.3	91	23	-63.68	-79.74	-80.40	-370	-16.8
Coke Drum Vent	2.8	0		1			0	0
Coke Handling & Storage				1	0.6	0.4		
3 & 4 SRU	0.6	9	2	2	10	10	-5	17.0
Sulfur Pits	0.0	0	0	-0.01	-0.01	-0.01	0	0
Beavon 2 Cooling Tower	-7			-116	-0.2	0.0		
Sulfur Storage and Loading	5.7	0	0	0	0	0	0	0
Flares	-930	-421	-77	-2	-8	-10	-11	-1.4
Tanks								
Storage	211							
Marine Loading	-84	2	2	0	0	0	0	0
Process								
Process Fugitives - Monitored	0	0	0	0	0	0	0	0
Process Fugitives - Unmonitored	1	0	0	0	0	0	0	0
Waste Water Treatment	-168	0	0	0	0	0	0	0
Total ATPA (tpy)	-950	-319	-51	-178	-78	-80	-386	-1.1
Significance Level	40	100	40	25	15	10	40	7
PSD Triggered	No	No	No	No	No	No	No	No

Appendix C

Draft Permit Conditions

**DEPARTMENT OF PLANNING
AND NATURAL RESOURCES**



**AIR POLLUTION CONTROL PROGRAM
AUTHORITY TO CONSTRUCT**

For:
**LIMETREE BAY TERMINALS, LLC/
LIMETREE BAY REFINING OPERATING, LLC**

EFFECTIVE DATE: XXX XX, 2018

PERMIT NUMBER: STX-XXX-18
(MARPOL Project)

THE PERMITTEE LIMETREE BAY TERMINALS, LLC/LIMETREE BAY REFINING OPERATING, LLC IS SUBJECT TO ALL TERMS, CONDITIONS, LIMITATIONS, AND STANDARDS CONTAINED HEREIN. THE CONDITIONS IN THIS PERMIT ARE FEDERALLY AND LOCALLY ENFORCEABLE.

Signed:

Norman Williams, Director

Date

SECTION I: FACILITY INFORMATION

PERMITTEE: Limetree Bay Terminals, LLC/Limetree Bay Refining Operating, LLC
#1 Estate Hope
Christiansted, VI 00820

SIC CODE: 2911

PERMIT NUMBER: STX-XXX-XXXX-18

FACILITY ADDRESS: #1 Estate Hope
Christiansted, VI 00820

MAILING ADDRESS: #1 Estate Hope
Christiansted, VI 00820

ISLAND: St. Croix

FACILITY CONTACT: Catherine Elizee
Environmental Staff Engineer
#1 Estate Hope
Christiansted, VI 00820 (340) 692-3073
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LIMETREE BAY TERMINALS, LLC/LIMETREE BAY REFINING OPERATING, LLC (hereinafter “**LIMETREE BAY TERMINALS, LLC**”) submitted to the U.S. Virgin Islands Department of Natural Resources (“Department”) a permit application dated April __, 2018 (the “Application”) proposing to resume refining operations at the St. Croix facility to meet local market demand and produce low sulfur fuels required by EPA regulations and international specifications and treaties. As part of this effort, **LIMETREE BAY TERMINALS, LLC** is proposing to modify the East Sulfur Recovery Plant, #5 Boiler, #8 Boiler, #9 Boiler, GT No. 7, GT No. 8, and to make repairs as necessary to resume operations as outlined in Table 1.

Table 1. MARPOL Project Equipment Description

Plant Area*	Process Unit	Source ID(s)	Unit Description	Project Description
Area I	Penex	Penex	Process Unit	Piping, fractionator stabilizer, and reactor distributor changes and heat exchanger addition
Area I	Penex	H-202	Hot Oil Heater	Repairs, resume operations
Area I	Penex	C-200A	Reciprocating Gas Compressor	Repairs, resume operations
Area I	Penex	C-200B	Reciprocating Gas Compressor	Repairs, resume operations
Area I	Penex	C-200C	Reciprocating Gas Compressor	Repairs, resume operations
Area III	#5 Crude Distillation Unit	#5 CDU	Process Unit	Piping changes, repairs, resume operations
Area III	#5 CDU	H-3101A	Crude Charge Heater	Repairs, resume operations
Area III	#5 CDU	H-3101B	Crude Charge Heater	Repairs, resume operations
Area III	#6 Crude Distillation Unit	#6 CDU	Process Unit	Piping changes, repairs, resume partial operations
Area III	No. 2 Gas Recovery Unit	2 GRU	Process Unit	Piping changes, repairs, resume operations
Area III	Gas Treatment	Unit No. 4800	Gas Treating	Repairs, resume operations
Area III	Gas Treatment	Unit No. 5800	Gas Treating	Replace No. 5 Amine Unit flash and rich amine pump (P-4837 A/B) or install a third pump, piping changes, repairs, resume operation
Area IV	#3 Vacuum Unit	#3 VAC	Process Unit	Piping changes, impeller replacement, repairs, resume operations
Area IV	#3 VAC	H-4201	Prestripper Heater	Repairs, resume operations
Area IV	#3 VAC	H-4202	Vacuum Heater	Repairs, resume operations
Area IV	#7 Distillate Desulfurizer	#7 DD	Process Unit	Piping changes, install chiller and on-line analyzer, repairs, resume operation
Area IV	#7 DD	Heater H-4301A	Reactor Charge Heater	Repairs, resume operations
Area IV	#7 DD	Heater H-4301B	Reactor Charge Heater	Repairs, resume operations
Area IV	#7 DD	Heater H-4302	Stripper Reboiler Heater	Repairs, resume operations
Area IV	#3 Platformer	#3 Plat	Process Unit	Repurpose Hydrobon section to light naphtha hydrotreater and reformer section to isomerization, install new reactor charge pumps, reactor feed / effluent heat exchangers, reactor charge heat exchanger, recycle gas dryer regeneration feed / effluent heat exchanger, recycle gas dryer regeneration cooler, and recycle gas driers, piping, repairs, resume operation

Plant Area*	Process Unit	Source ID(s)	Unit Description	Project Description
Area IV	#3 Platformer	Heater H-4401	Charge Heater	Repairs, resume operations
Area IV	#3 Platformer	Heater H-4402	Fired Reboiler Heater	Repairs, resume operations
Area IV	#3 Platformer	Heater H-4455	Fired Reboiler Heater	Repairs, resume operations
Area IV	#6 Distillate Desulfurizer	#6 DD	Process Unit	Install piping and control valves, effluent exchanger, reactor hydrogen quench system, on-line analyzer, piping, repairs, resume operation
Area IV	#6 DD	H-4601A	Reactor Charge Heater	Repairs, resume operations
Area IV	#6 DD	H-4601B	Reactor Charge Heater	Repairs, resume operations
Area IV	#6 DD	H-4602	Stripper Reboiler Heater	Repairs, resume operations
Area IV	#6 DD	C-4601A	Reciprocating Gas Compressor	Repairs, resume operations
Area IV	#6 DD	C-4601B	Reciprocating Gas Compressor	Repairs, resume operations
Area IV	#6 DD	C-4601C	Reciprocating Gas Compressor	Repairs, resume operations
Area IV	#4 Platformer	#4 Platformer	Process Unit	Use Hydrobon section as a naphtha hydrotreater and reformer section as naphtha reformer, install chlorine gas treater and LPG treater, piping, repairs, and resume operations
Area IV	#4 Platformer	H-5401	Charge Heater	Repairs, resume operations
Area IV	#4 Platformer	H-5402	Fired Reboiler Heater	Repairs, resume operations
Area IV	#4 Platformer	H-5451	Charge Heater	Repairs, resume operations
Area IV	#4 Platformer	H-5452	Intermediate Heater	Repairs, resume operations
Area IV	#4 Platformer	H-5453	Intermediate Heater	Repairs, resume operations
Area IV	#4 Platformer	H-5454	Intermediate Heater	Repairs, resume operations
Area IV	#4 Platformer	H-5455	Fired Reboiler Heater	Repairs, resume operations
Area IV	#9 Distillate Desulfurizer	#9 DD	Process Unit	Repairs, resume operations
Area IV	#9 Distillate Desulfurizer	H-5301A	Reactor Charge Heater	Repairs, resume operations
Area IV	#9 Distillate Desulfurizer	H-5301B	Reactor Charge Heater	Repairs, resume operations
Area IV	#9 Distillate Desulfurizer	H-5302	Stripper Reboiler Heater	Repairs, resume operations
Area V	#6 Amine	Unit No. 7450	Process Unit	Install tie-in to East Sulfur Plant TGTU and rich amine pump, repairs, and resume operations
Area V	#7 Amine	Unit No. 7460	Process Unit	Repairs, resume operations
Area VI	East Sulfur Recovery	#3 SRU	Unit No. 4740	Replace air blowers, primary burner, intra-stage reheaters, reload catalyst, piping, repairs, and resume operations

Plant Area*	Process Unit	Source ID(s)	Unit Description	Project Description
Area VI	East Sulfur Recovery	#4 SRU	Unit No. 4750	Replace air blowers, primary burner, reload catalyst, piping, repairs, and resume operations
Area VI	East Sulfur Recovery	#2 Beavon	H-4761 (T-4761)	Convert #2 Beavon to a Shell Claus Offgas Treater ("SCOT") type TGTU (change hydrogenation reactor catalyst, replace fired reheater with steam reheater, install quench column, absorber, pumps, and quench water cooler, and filter system), piping, repairs, and resume operations
Area VI	East Sulfur Recovery	H-4745	East Incinerator	Repairs, resume operations
Area VI	East Sulfur Recovery	#3 and #4 SRU	East Sulfur Pits	Install sulfur pit eductor system, piping, repairs, and resume operations
Area VI	East Sulfur Storage Area	Materials Handling	Materials Handling	Repairs, resume operations
Area VI	Advanced Wastewater Treatment System	#2 API (Unit No.1660)	Oil/Water Separator	Repairs, resume operations
Area VI	Advanced Wastewater Treatment System	#2 WEMCO	Induced Air Floatation	Repairs, resume operations
Area VI	Advanced Wastewater Treatment System	West Benzene Stripper (STK-3510)	Air Stripper	Repairs, resume operations
Area VI	Advanced Wastewater Treatment System	East Benzene Stripper (STK-3530)	Air Stripper	Repairs, resume operations
Area VI	Advanced Wastewater Treatment System	#3 WEMCO	Induced Air Floatation	Repairs, resume/continue operations
Area VI	Advanced Wastewater Treatment System	Miscellaneous Equipment	Process Unit	Piping changes, repairs, resume/continue operations
Area VI	Advanced Wastewater Treatment System	#3 & #4 Sour Water Strippers (Unit No. 4720/30)	Steam Stripper	Repairs, resume operations
Area VI	Advanced Wastewater Treatment System	#5 Sour Water Strippers (Unit No. 7400)	Steam Stripper	Repairs, resume operations
Area VI	Advanced Wastewater Treatment System	CPS Oil/Water Separator	Oil/Water Separator	Repairs, resume operations
Area VI	Refinery Flare System	#3 Flare (H-1104)	Gas Burner	Repairs, resume operations
Area VI	Refinery Flare System	#5 Flare (H-3351)	Gas Burner	Repairs, resume operations
Area VI	Refinery Flare System	#7 Flare (H-3301)	Gas Burner	Repairs, resume operations
Area VI	Refinery Flare System	LPG Flare (STK-7921)	Gas Burner, steam assist	Repairs, resume operations
Area VI	Refinery Flare System	FCC Flare (L.P. Flare - STK 7941)	Gas Burner, steam assist	Repairs, resume operations

Plant Area*	Process Unit	Source ID(s)	Unit Description	Project Description
Area VI	Refinery Flare System	Ground Flare (H.P. Flare - STK-7942)	Gas Burner	Repairs, resume operations
Area VII	Delayed Coker Unit	DCU	Process Unit	Install blowdown eductor system and additional instrumentation, piping, repairs, resume operations
Area VII	Delayed Coker Unit	H-8501A	Coker Process Heater 1	Repairs, resume operations
Area VII	Delayed Coker Unit	H-8501B	Coker Process Heater 2	Repairs, resume operations
Area VII	Delayed Coker Unit	TK-8501 (Hot pitch tank)	Fixed roof storage tank	Repairs, resume operations
Area VII	Delayed Coker Unit	TK-8502 (Quench water tank)	Open roof tank	Repairs, resume operations
Area VII	Coker Complex	Coke handling, storage, & loading system	Transportation & breaking of solid coke between drums & dock	Repairs, resume operations
Area VII	Coker Complex	Tank TK-8511 & Residuals Recycling System	Tank TK-8511 & recycling system	Repairs, resume operations
Area VIII	Utility II	#5 Boiler (B-1155)	Boiler; Produces Steam	Install NO _x Control, repairs, resume operations
Area VIII	Utility III	#8 Boiler (B-3303)	Boiler; Produces Steam	Install NO _x Control, repairs, resume operations
Area VIII	Utility III	#9 Boiler (B-3304)	Boiler; Produces Steam	Install NO _x Control, repairs, resume operations
Area VIII	Utility III	#10 Boiler (B-3701)	Boiler; Produces Steam	Repairs, resume operations
Area VIII	Powerhouse 2	GT No. 7 (G-3407)	Turbine; Produces Electricity	Install SCR, repairs
Area VIII	Powerhouse 2	GT No. 8 (G-3408)	Turbine; Produces Electricity	Install SCR, repairs
Area VIII	Powerhouse 2	GT No. 9 (G-3409)	Turbine; Produces Electricity	Repairs, resume operations
Area VIII	Powerhouse 2	GT No. 10 (G-3410)	Turbine; Produces Electricity	Repairs, resume operations
Area VIII	GT No. 13 and Duct Burner	GT No. 13 (G-3413)	Turbine; Produces Electricity	Repairs, resume operations
Area VIII	GT No. 13 and Duct Burner	H-3413	Duct Burner	Repairs, resume operations
Area IX	Tank	TK-1663	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-6814	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-6815	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-6816	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-6825	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-6836	External Floating Roof	Repairs, continue/resume operations

Plant Area*	Process Unit	Source ID(s)	Unit Description	Project Description
Area IX	Tank	TK-6838	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-6839	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-6840	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-6841	Internal Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7405	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7406	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7413	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7415	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7418	Internal Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7425	Internal Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7426	Internal Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7427	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7443	External Floating	Repairs, continue/resume operations
Area IX	Tank	TK-7446	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7447	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7448	Internal Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7501	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7502	Fixed Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7510	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7511	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7512	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7513	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7515	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7516	External Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7603	Internal Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7604	Internal Floating Roof	Repairs, continue/resume operations
Area IX	Tank	TK-7605	External Floating Roof	Repairs, continue/resume operations
Area X	Piping	Unit No. 1902	East/West fuel gas system	Repairs, continue/resume operations
Area X	Piping	Unit No. 3303	East/West fuel gas system	Repairs, continue/resume operations
Area X	Storage Pile and Conveyor	N/A	Sulfur Storage and Ship Loading	Repairs, resume operations

* Per Title V Permit No. STX-TV-003-10

This Authority to Construct is issued under the authority of the Virgin Islands Air Pollution Control Act and Virgin Islands Rules and Regulations Title 12, Chapter 9, §206-26, §206-27 and §206-31 and permits the construction identified in Section I and the Application.

SECTION II: REGULATORY REQUIREMENTS

LIMETREE BAY TERMINALS, LLC shall continue to comply with applicable regulatory requirements as defined in the St. Croix facility Title V Permit No. STX-TV-003-10, for all emission units affected but not modified by the MARPOL Project. For the affected facilities and sources that are modified by the MARPOL Project, the only changes from the requirements in the Title V permit are summarized in Table 2. Where a term or condition of this Permit differs from, modifies or changes a provision of Title V Permit No. STX-TV-003-10, **LIMETREE BAY TERMINALS, LLC** agrees to comply with the terms and conditions of this Permit in lieu of those in the Title V Permit until such permit is amended to reflect the terms and conditions of this Permit.

1. Based on the information submitted in the Application and supporting documents for the MARPOL Project is subject to the regulations outlined in Table 2.

Table 2. Applicable Regulations

Regulation	Affected Source and Section
40 CFR Part 60, Subpart A: General Provisions	Area wide requirement
40 CFR Part 60, Subpart Ja: Petroleum Refineries	East Sulfur Recovery Plant conversion to a reduction control system followed by an incinerator
40 CFR Part 60, Subpart GGa: Equipment Leaks of VOC in Petroleum Refineries which construction, reconstruction or modification commenced after November 7, 2006	As applicable, equipment in VOC service
40 CFR Part 63, Subpart A: General Provisions	Area wide requirement.
40 CFR Part 63, Subpart CC: Petroleum Refineries	Petroleum refinery process units and associated emission points
40 CFR Part 63, Subpart UUU: NESHAP for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units	#3 Plat, #4 Plat, and East Sulfur Recovery Plant
40 CFR Part 63, Subpart ZZZZ: NESHAP for Stationary Reciprocating Internal Combustion Engines	Penex Reciprocating Gas Compressors

Regulation	Affected Source and Section
40 CFR Part 63, Subpart DDDDD: NESHP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	All existing boilers and process heaters at Limetree Bay.

2. In addition to the regulatory requirements summarized in Table 2 above, **LIMETREE BAY TERMINALS, LLC** shall comply with the applicable provisions of 40 CFR §52.21(r)(6).
3. For the purposes of the foregoing Section II.2, the following provisions shall apply:
 - (a) Annual emissions shall be based on:
 - i. Department or U.S. Environmental Protection Agency (USEPA) policies in effect, AP-42, or engineering estimates;
 - ii. Actual data to determine the activity rate; and
 - iii. Account for the control equipment.

Department and USEPA regulations and policies have established a hierarchy of emissions rate information to be used in calculation of emissions. Annual emissions shall be calculated using the most reliable emissions rates available.
 - (b) **STX-XXX-XXXX** (MARPOL Project) contain provisions relevant to the calculation of emissions rates, such as stack testing or monitoring and recording of process parameters. **LIMETREE BAY TERMINALS, LLC** is authorized to use this information to comply with Section II.2 in the calculation of annual emissions.
 - (c) Nothing in the MARPOL Project Permit shall require **LIMETREE BAY TERMINALS, LLC** to monitor or record information relating to annual emissions in addition to the information required by the MARPOL Project Permit.

SECTION III: SPECIFIC CONDITIONS FOR THE MARPOL PROJECT

LIMETREE BAY TERMINALS, LLC is proposing to resume operations of some of the St. Croix facility refining process units (the “MARPOL Project”). The MARPOL Project will comprise modification of the East Sulfur Recovery Plant to increase its capacity and convert the #2 Beavon tailgas treatment unit to a reduction control system followed by an incinerator (East Incinerator) and various equipment changes in the #5 CDU, #3 VAC, #7 DD, #3 Plat, #6 DD, #4 Plat, Penex, #9 DD, #2 GRU, Gas Treatment (Unit No. 4800), Gas Treatment (Unit No. 5800), #6 Amine, and #7 Amine process units to support resumption of refining operations at the St. Croix facility to meet local market demand and produce low sulfur fuels required by EPA regulations and international specifications and treaties. Additionally, **LIMETREE BAY TERMINALS,**

LLC is proposing to install selective catalytic reduction (SCR) systems on GT-7 and GT-8 and installation of NO_x controls on Boilers #5, #8 and #9 to meet the NSPS subpart D standards.

A. OPERATIONAL REQUIREMENTS

4. **LIMETREE BAY TERMINALS, LLC** shall comply with standards outlined in § 60.592a, of 40 CFR Part 60, Subpart GGGa as applicable.
5. **LIMETREE BAY TERMINALS, LLC** is subject to and will comply with 40 CFR Part 63, Subpart CC as amended [80 FR 75253, Dec. 1, 2015]: National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (“NESHAP”).
6. **LIMETREE BAY TERMINALS, LLC** is subject to and will comply with 40 CFR Part 63, Subpart UUU as amended [80 FR 75273, Dec. 1, 2015]: NESHAP for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.
7. **LIMETREE BAY TERMINALS, LLC** is subject to and will comply with 40 CFR Part 63, Subpart ZZZZ as amended [69 FR 33506, June 15, 2004]: NESHAP for Stationary Reciprocating Internal Combustion Engines.
8. **LIMETREE BAY TERMINALS, LLC** is subject to and will comply with 40 CFR Part 63, Subpart DDDDD: NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.
9. Prior to building, erecting, altering or replacing any article, machine, equipment or other contrivance other than those subject to this Permit, the use of which may cause the issuance of air contaminants or may eliminate or reduce or control the issuance of air contaminants, **LIMETREE BAY TERMINALS, LLC** shall first obtain a written Authority to Construct from the Commissioner or his designated representative. [12 V.I. R & R § 206-20(a)(1995)].
10. Prior to operation at any other location, **LIMETREE BAY TERMINALS, LLC** must submit a separate application for an Authority to Construct the equipment(s) at each new location or construction project that will be conducted on noncontiguous property. [12 V.I. R & R § 206-21(a)(1995)].
11. Construction and operation of the sources authorized by this Permit will not prevent the attainment or maintenance of any ambient air quality standard and will not result in a violation of any provision of this chapter or the Virgin Islands State Implementation Plan [12V.I. R & R § 206-26(a)(2)(1995) and 12 V.I. R & R § 206-27(a)(1)(B) (1995)].
12. **LIMETREE BAY TERMINALS, LLC** shall not cause or permit the discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, annoyance to persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public or which cause or have tendency to cause injury or damage to business or property. [12 V.I. R. & R § 204-27(a)].

13. Nothing in any other regulation concerning emission of air contaminants, or any other regulations relating to air pollution, shall in any manner be construed as authorizing or legalizing the creation or maintenance of a nuisance described in the above-mentioned condition.
14. **LIMETREE BAY TERMINALS, LLC** shall comply with sulfur compound emission control outlined in 12 V.I.R& R § 204-26(a)(1) and (b) for the emissions sources.
15. **LIMETREE BAY TERMINALS, LLC** shall not build, erect, install or use any article, machine, equipment or other contrivance, the sole purpose of which is to dilute or conceal an emission without resulting in a reduction in the total release of air contaminants to the atmosphere. [12 V.I.R& R § 204-30]
16. It shall be the duty of **LIMETREE BAY TERMINALS, LLC** to report any discontinued or dismantled fuel burning, combustion or process equipment or device coming under the jurisdiction of the permit provision of this chapter within thirty (30) days of permanent discontinuance or dismantlement of such equipment or device. [12 V.I.R& R § 204-31].
17. **LIMETREE BAY TERMINALS, LLC** must report to the Department any physical change or changes in construction which increase the amount of air pollutants or process production.
18. During construction, any source subject to this Permit, which is responsible for contravening ambient air quality standards, will be required to be modified to bring operation into compliance.

B. SPECIFIC EQUIPMENT CONDITIONS

1. **East Sulfur Recovery Plant**

- (a) **LIMETREE BAY TERMINALS, LLC** shall use the SCOT type TGTU to control tailgas from the Nos. 3 and 4 Sulfur Recovery Units.
- (d) Exhaust from the SCOT type TGTU shall be directed to the East Incinerator (H-4745).
- (e) During periods of sulfur recovery plant (*i.e.*, SRUs and TGTU) startup, shutdown, or malfunction the tailgas shall be routed directly to the East Incinerator (H-4745).

2. **Gas Turbine Steam Generators GT-7 and GT-8**

- (a) **LIMETREE BAY TERMINALS, LLC** shall fire solely gaseous fuel or No. 2 oil with a maximum sulfur content of 0.1% weight.
- (b) **LIMETREE BAY TERMINALS, LLC** must operate the selective catalytic reduction (“SCR”) in GT-7 and GT-8, for the purpose of NO_x control, at all times except during periods of startup, shutdown or maintenance of the gas turbines.
- (c) **LIMETREE BAY TERMINALS, LLC** shall operate and maintain the SCRs in

accordance with the manufacturer's specifications.

3. **Boilers #5, #8 and #9**

- (a) **LIMETREE BAY TERMINALS, LLC** shall fire gaseous fuel.
- (b) **LIMETREE BAY TERMINALS, LLC** must operate the NO_x controls in Boilers #5, #8 and #9 at all times except during periods of startup, shutdown, or maintenance of the boilers.

C. EMISSIONS LIMITS AND WORK PRACTICES

4. **East Sulfur Recovery Plant**

- a. East Sulfur Recovery Plant is subject to NSPS subpart Ja: Standards of Performance for Petroleum Refineries
- b. **LIMETREE BAY TERMINALS, LLC** shall comply with standards outlined in § 60.102a(f)(1)(i) as applicable to an oxidation control system or a reduction control system followed by incineration.
- c. The emissions from the East Incinerator shall not exceed the limitations in Table 3.

Table 3. MARPOL Project Modified Unit Emission Limits

Air Pollutant	Annual Emissions (tpy)⁽¹⁾
NO _x	24
CO	20
VOC	1.3
SO ₂	282
PM	4

(1) Emissions corresponding to East Incinerator H-4745.

D. TESTING REQUIREMENTS

- 1. At least 60 days prior to the actual stack testing, where required by this Permit, **LIMETREE BAY TERMINALS, LLC** shall submit to the Department a written protocol detailing the methods and procedures to be used during the performance testing as applicable. The Department, in their discretion, may waive all or a portion of that period.
- 2. **LIMETREE BAY TERMINALS, LLC** shall notify the Department at least 30 days prior to conducting a performance test, if required by this Permit. The Department, in their discretion, may waive all or a portion of that 30-day period.

3. **LIMETREE BAY TERMINALS, LLC** shall provide permanent or other sampling and testing facilities as may be required by the Department to determine the nature and quantity of emissions for each unit. Such facilities shall conform to all applicable laws and regulations concerning safe construction and practice.
4. **LIMETREE BAY TERMINALS, LLC** shall conduct performance test performance tests required in 40 CFR §60.8 and shall use as reference methods and procedures the test methods in appendix A to 40 CFR Part 60 or other methods and procedures as specified in 40 CFR Part 60, except as provided in 40 CFR §60.8(b).
5. **LIMETREE BAY TERMINALS, LLC** shall determine compliance with the SO₂ standard at 40 CFR § 60.104(a)(2) in accordance with the test method and procedures at 40 CFR § 60.106(f).
6. **LIMETREE BAY TERMINALS, LLC** shall determine compliance with the NO_x standard at 40 CFR § 60.332(a)(2) in accordance with the procedures at 40 CFR § 60.335.

E. MONITORING REQUIREMENTS

1. All monitors, recorders and meter devices, if required by this Permit, shall be installed prior to operation of the equipment, unless otherwise stated. **LIMETREE BAY TERMINALS, LLC** shall maintain and calibrate, in a manner consistent with the manufacturer's specifications, all monitors, meters, hydrocarbon analyzers, and recorders as required above. All specifications must be made available to representatives of the Department upon request.
2. All monitors, recorders and meters required in this Permit shall be located in a manner which allows easy access and visibility. The Department may require relocation of the monitor or remote readout equipment.

F. RECORDKEEPING AND REPORTING

1. **LIMETREE BAY TERMINALS, LLC** shall comply with the reporting and recordkeeping requirements as applicable, to affected facilities authorized by this Permit, as outlined in 40 CFR Part 60, Subpart A.
2. **LIMETREE BAY TERMINALS, LLC** shall comply with the notification, reporting and recordkeeping requirements as applicable, as outlined in Section §60.7 in 40 CFR Part 60, Subpart A.
3. **LIMETREE BAY TERMINALS, LLC** shall comply with the reporting and recordkeeping requirements as applicable, as outlined in Section §60.592a in 40 CFR Part 60, Subpart GGGa.
4. **LIMETREE BAY TERMINALS, LLC** shall comply with the notification, reporting and recordkeeping requirements as applicable, as outlined in Section §63.10 in 40 CFR Part 63,

Subpart A.

5. **LIMETREE BAY TERMINALS, LLC** shall comply with the reporting and recordkeeping requirements as applicable, as outlined in Section § 63.655 in 40 CFR Part 63, Subpart CC.
6. **LIMETREE BAY TERMINALS, LLC** shall comply with the reporting and recordkeeping requirements as applicable, as outlined in Section §§ 63.1575 and 1576 in 40 CFR Part 63, Subpart UUU.
7. **LIMETREE BAY TERMINALS, LLC** shall comply with the reporting and recordkeeping requirements as applicable, as outlined in Section §§ 63.6650 and 6655 in 40 CFR Part 63, Subpart ZZZZ.
8. **LIMETREE BAY TERMINALS, LLC** shall comply with the reporting and recordkeeping requirements as applicable, as outlined in Section §§ 63.7550 and 7555 in 40 CFR Part 63, Subpart DDDDD.
9. **LIMETREE BAY TERMINALS, LLC** shall maintain all records necessary for determining compliance with this Permit in a readily accessible location for five (5) years, except as otherwise required by Section II.2 of this permit and shall make these records available to the Department upon written or verbal request. All such records must be initialed or signed by the person recording the information or maintained in a verifiable electronic system whose information can be certified as to its accuracy.
10. **LIMETREE BAY TERMINALS, LLC** shall submit a written notification to the Department of the date of commencement of construction as authorized in this Permit, and to be postmarked no later than 30 days after such time.

SECTION IV: FACILITY WIDE REQUIREMENTS

1. **LIMETREE BAY TERMINALS, LLC** shall also comply with any other emission limits, testing, monitoring, recordkeeping and reporting required pursuant to the Virgin Islands rules and regulations.
2. Where an applicable requirement of the Clean Air Act, as amended 42 U.S.C. §7401 (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit and the Commissioner or the Administrator can enforce both provisions.
3. Compliance with any annual limitations of this Permit shall be determined from a running total of 12 months of data unless otherwise specified in a particular condition.
4. All records and data required to demonstrate compliance in this Permit shall be submitted to the Department upon request.
5. **LIMETREE BAY TERMINALS, LLC** must operate and maintain all operating equipment, air pollution control equipment, and monitoring equipment in a manner

consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

6. **LIMETREE BAY TERMINALS, LLC** shall ensure that any fugitive dust associated with the construction or installation of the equipment covered by this Permit is minimized and controlled.
7. **LIMETREE BAY TERMINALS, LLC** must construct and/or install the equipment, control apparatus and emission monitoring equipment within the design limitations.
8. **LIMETREE BAY TERMINALS, LLC** shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to twenty percent (20%) for any time period, except for a period or periods aggregating not more than 3 minutes in any 30-minute period when opacity shall be less than or equal to 40%. [12 V. I. R&R 204-22(a) and (b)].
9. For the purpose of ascertaining compliance or non-compliance with any air pollution control rule or regulation, the Commissioner may require **LIMETREE BAY TERMINALS, LLC** who owns such air contamination source, to conduct acceptable tests to measure emissions.
10. **LIMETREE BAY TERMINALS, LLC** shall not cause or permit any materials to be handled, transported, or stored in a building, its appurtenances, or cause a road to be used, constructed, altered, repaired or demolished without taking the necessary precautions to prevent particulate matter from becoming airborne. [12 V. I. R&R 204-25(a)(1) through (9)].
11. The Commissioner may require other reasonable measures as may be necessary to prevent particulate matter from becoming airborne.
12. **LIMETREE BAY TERMINALS, LLC** shall not cause or permit the discharge of visible emissions of fugitive dust beyond the boundary line of the property on which their emissions originate.
13. **LIMETREE BAY TERMINALS, LLC** must maintain the following records of monitoring information if monitoring is required by this Permit.
 - (a) The date, location and time of sampling or measurements
 - (b) The date(s) analyses performed
 - (c) The company or entity performing the analyses
 - (d) The analytical techniques or methods used
 - (e) The result of such analyses
 - (f) The facility's status at the time of sampling or measurements.

SECTION V: GENERAL REQUIREMENTS

1. This Authority to Construct shall automatically become invalid one (1) year after the date of its issuance, unless the construction or modification has commenced or an application for extension, in the form of a letter to the Commissioner, is made thirty (30) days prior to the expiration date of the Permit.
2. Any revisions to activities described in the permit application and authorized in this Permit must be approved by the Commissioner prior to commencement of operations.
3. In the case that this Permit is subject to any challenge by third parties, the effectiveness of the Permit stands until any judicial court decides the contrary.
4. Failure of the Commissioner to act on a permit application shall not be deemed issuance by default.
5. **LIMETREE BAY TERMINALS, LLC** must comply with all conditions of this Permit. Any permit noncompliance constitutes a violation and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.
6. All terms and conditions contained herein shall be enforceable by the USEPA and citizens of the United States under the Clean Air Act, as amended, 42 U.S.C. § 7401, *et seq.*
7. Nothing in this Permit shall alter or affect the authority of the USEPA to obtain information pursuant to 42 U.S.C. § 7414, "Inspections, Monitoring, and Entry".
8. **LIMETREE BAY TERMINALS, LLC** shall not claim as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.
9. The Department may modify, revoke, reopen and reissue the Permit or terminate the Permit for cause [12 V.I.R. & R § 206-28]. The filing of a request by the source for a permit modification, revocation and reissuance, or termination or the filing of a notification of planned changes or anticipated noncompliance does not stay any permit condition.
10. This Permit does not convey any property rights of any sort, or any exclusive privilege.

11. Issuance of this Permit does not relieve the **LIMETREE BAY TERMINALS, LLC** from the responsibility of obtaining and complying with any other permits, licenses, or approvals required by the Department or any other federal, territorial, or local agency.
12. Nothing in this Permit shall alter or affect the liability of **LIMETREE BAY TERMINALS, LLC** for any violation of applicable requirements prior to or at the time of Permit issuance.
13. Any condition or portion of this Permit, which is challenged, becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this Permit.
14. Compliance with the terms of this Permit shall be deemed compliance with all applicable requirements as of the date of Permit issuance, provided that all applicable requirements are included and specifically identified in the Permit or permit application.
15. In accordance with 12 V.I. R.&R. §206-65, the Department shall allow certain defined changes at permitted facilities that contravene permit terms or conditions or make them inapplicable without requiring a permit revision. Such changes may not include changes that violate applicable requirements or contravene permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.
16. If after notification as described in Condition 16 above, the Department deems that the change implemented by the source does not qualify under § 206-65(b), the original terms of the permit remain fully enforceable.
17. Provisions for operational flexibility do not preclude a source's obligation to comply with all applicable requirements.
18. Any application forms, all reports, or compliance certifications submitted pursuant to this Permit shall contain a certification of truth, accuracy and completeness signed by a responsible official of the facility. Any certification submitted by the facility shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.
19. Information contained in permit applications shall be public, except that which is claimed confidential in accordance with the Virgin Islands Air Pollution Control Act. The contents of the permit itself are not entitled to confidentiality.
20. **LIMETREE BAY TERMINALS, LLC** must allow an authorized representative of the Department, upon presentation of credentials, to perform the following:
 - (a) Enter upon **LIMETREE BAY TERMINALS, LLC** premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

- (b) Have access to and copy, at reasonable times, any records required under the conditions of this permit;
 - (c) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
 - (d) As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.
21. **LIMETREE BAY TERMINALS, LLC** shall furnish to the Department, in writing, information that the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit.
22. Upon request, the **LIMETREE BAY TERMINALS, LLC** shall furnish to the Department copies of records that this facility is required to keep by this Permit, which information may be claimed to be confidential in accordance with the Virgin Islands Air Pollution Control Act. **LIMETREE BAY TERMINALS, LLC** may furnish such records directly to the Department, if necessary, along with a claim of confidentiality.
23. A copy of this Permit shall be kept on-site at **LIMETREE BAY TERMINALS, LLC**.

Appendix D

Supporting Documents

- **83 FR 13745:** Issuance of Guidance Memorandum, “Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program”
- **Memorandum:** “Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program,” Pruitt E. Scott, Administrator to Regional Administrators, March 13, 2018.
- **Letter** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation, U.S. EPA, to LeAnn Johnson Koch, Perkins Coie, April 5, 2018.

FOR FURTHER INFORMATION CONTACT:

Karen Seeh, U.S. Environmental Protection Agency, Office of Environmental Information, Mail Stop 2823T, 1200 Pennsylvania Avenue NW, Washington, DC 20460, (202) 566-1175, seeh.karen@epa.gov.

SUPPLEMENTARY INFORMATION: On October 13, 2005, the final Cross-Media Electronic Reporting Rule (CROMERR) was published in the *Federal Register* (70 FR 59848) and codified as part 3 of title 40 of the CFR. CROMERR establishes electronic reporting as an acceptable regulatory alternative to paper reporting and establishes requirements to assure that electronic documents are as legally dependable as their paper counterparts. Subpart D of CROMERR requires that state, tribal or local government agencies that receive, or wish to begin receiving, electronic reports under their EPA-authorized programs must apply to EPA for a revision or modification of those programs and obtain EPA approval. Subpart D provides standards for such approvals based on consideration of the electronic document receiving systems that the state, tribe, or local government will use to implement the electronic reporting. Additionally, § 3.1000(b) through (e) of 40 CFR part 3, subpart D provides special procedures for program revisions and modifications to allow electronic reporting, to be used at the option of the state, tribe or local government in place of procedures available under existing program-specific authorization regulations. An application submitted under the subpart D procedures must show that the state, tribe or local government has sufficient legal authority to implement the electronic reporting components of the programs covered by the application and will use electronic document receiving systems that meet the applicable subpart D requirements.

On February 14, 2018, the Missouri Department of Natural Resources (MoDNR) submitted an application titled "Missouri Gateway to Environmental Management" for revisions/modifications to its EPA-approved programs under title 40 CFR to allow new electronic reporting. EPA reviewed MoDNR's request to revise/modify its EPA-authorized programs and, based on this review, EPA determined that the application met the standards for approval of authorized program revisions/modifications set out in 40 CFR part 3, subpart D. In accordance with 40 CFR 3.1000(d), this notice of EPA's decision to approve Missouri's request to revise/modify its following EPA-authorized programs to

allow electronic reporting under 40 CFR parts 50–52, 60–65, 70, 122, 125, 141, 144, 146, 240–259, 260–270, 272–279, 280, 403–471, and 763 is being published in the *Federal Register*:

Part 52—Approval and Promulgation of Implementation Plans;

Part 62—Approval and Promulgation of State Plans for Designated Facilities and Pollutants;

Part 63—National Emission Standards for Hazardous Air Pollutants for Source Categories;

Part 70—State Operating Permit Programs;

Part 123—EPA Administered Permit Programs: The National Pollutant Discharge Elimination System;

Part 142—National Primary Drinking Water Regulations Implementation;

Part 145—State Underground Injection Control Programs;

Part 239—Requirements for State Permit Program Determination of Adequacy;

Part 271—Requirements for Authorization of State Hazardous Waste Program;

Part 281—Technical Standards and Corrective Action Requirements for Owners and Operators of Underground Storage Tanks;

Part 403—General Pretreatment Regulations for Existing and New Sources of Pollution; and

Part 763—Asbestos.

MoDNR was notified of EPA's determination to approve its application with respect to the authorized programs listed above.

Also, in today's notice, EPA is informing interested persons that they may request a public hearing on EPA's action to approve the State of Missouri's request to revise its authorized public water system program under 40 CFR part 142, in accordance with 40 CFR 3.1000(f). Requests for a hearing must be submitted to EPA within 30 days of publication of today's *Federal Register* notice. Such requests should include the following information: (1) The name, address and telephone number of the individual, organization or other entity requesting a hearing;

(2) A brief statement of the requesting person's interest in EPA's determination, a brief explanation as to why EPA should hold a hearing, and any other information that the requesting person wants EPA to consider when determining whether to grant the request;

(3) The signature of the individual making the request, or, if the request is made on behalf of an organization or other entity, the signature of a responsible official of the organization or other entity.

In the event a hearing is requested and granted, EPA will provide notice of the hearing in the *Federal Register* not less than 15 days prior to the scheduled hearing date. Frivolous or insubstantial requests for hearing may be denied by EPA. Following such a public hearing, EPA will review the record of the hearing and issue an order either affirming today's determination or rescinding such determination. If no timely request for a hearing is received and granted, EPA's approval of the State of Missouri's request to revise its part 142—National Primary Drinking Water Regulations Implementation program to allow electronic reporting will become effective 30 days after today's notice is published, pursuant to CROMERR section 3.1000(f)(4).

Matthew Leopard,

Director, Office of Information Management.

[FR Doc. 2018-06429 Filed 3-29-18; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

[FRL-9975-25-OAR]

Issuance of Guidance Memorandum, "Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program"

AGENCY: Environmental Protection Agency (EPA).

ACTION: Issuance of guidance memorandum.

SUMMARY: The Environmental Protection Agency (EPA) is notifying the public that it has issued the guidance memorandum titled "Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program."

ADDRESSES: You may view this guidance memorandum electronically at: <https://www.epa.gov/nsr/project-emissions-accounting>.

FOR FURTHER INFORMATION CONTACT: Juan Santiago, Air Quality Policy Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541-1084; and email address: santiago.juan@epa.gov.

SUPPLEMENTARY INFORMATION: On March 13, 2018, the EPA issued a guidance memorandum that addresses the accounting of emissions changes resulting from a project under Step 1 of the New Source Review (NSR) applicability process in the EPA regulations. Step 1 of the NSR

applicability process requires a determination of whether a proposed project will, by itself, result in a significant emissions increase. As explained in the memorandum, it is the EPA's interpretation that its current NSR regulations provide that emissions decreases as well as increases are to be considered at Step 1 of the NSR applicability process. This interpretation is grounded in the principle that the plain language of the Clean Air Act indicates that Congress intended to apply NSR to changes that increase actual emissions and the language in the corresponding NSR regulations is consistent with that intent.

Prior EPA guidance had indicated that the relevant provisions of the NSR regulations preclude the consideration of emissions decreases at Step 1. For the reasons discussed in the memorandum, the EPA has revised its interpretation of the regulatory language and will no longer apply any such interpretation reflected in prior statements on this issue.

Dated: March 13, 2018.

Panagiotis E. Tsirigotis,

Director, Office of Air Quality Planning and Standards.

[FR Doc. 2018-06430 Filed 3-29-18; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

[ER-FRL-9038-4]

Environmental Impact Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information (202) 564-7156 or <https://www2.epa.gov/nepa>.

Weekly receipt of Environmental Impact Statements

Filed 03/19/2018 Through 03/23/2018 Pursuant to 40 CFR 1506.9.

Notice

Section 309(a) of the Clean Air Act requires that EPA make public its comments on EISs issued by other Federal agencies. EPA's comment letters on EISs are available at: <https://cdxnodengn.epa.gov/cdx-nepa-public/action/eis/search>.

EIS No. 20180048, Draft, FHWA, TX, SH 68 from I-2/US 83 to I-69C/US 281, Comment Period Ends: 05/14/2018, Contact: Margil Maldonado 956-702-6134

EIS No. 20180049, Final, NOAA, CA, CALAM Monterey Peninsula Water Supply Project FEIR/FEIS, Review

Period Ends: 04/30/2018, Contact: Karen Grimmer 831-647-4253

EIS No. 20180050, Final, USFS, SD, Black Hills Resilient Landscapes Project, Review Period Ends: 04/30/2018, Contact: Anne Davy 406-273-1836

EIS No. 20180051, Final, USFS, CA, Highway 89 Safety Enhancement and Forest Ecosystem Restoration Project, Review Period Ends: 04/30/2018, Contact: Ann Glubczynski 530-964-3717

EIS No. 20180052, Draft, FERC, NY, Northeast Supply Enhancement Project, Comment Period Ends: 05/14/2018, Contact: Christine Allen 202-502-6847

Dated: March 27, 2018.

Kelly Knight,

Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 2018-06419 Filed 3-29-18; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

[EPA-R10-OAR-2017-0516; FRL-9976-07-OEI]

Information Collection Request Submitted to OMB for Review and Approval; Comment Request; Federal Implementation Plans Under the Clean Air Act for Indian Reservations in Idaho, Oregon and Washington (Renewal)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Environmental Protection Agency (EPA) has submitted an information collection request (ICR), "Federal Implementation Plans under the Clean Air Act for Indian Reservations in Idaho, Oregon and Washington (EPA ICR No. 2020.07, OMB Control No. 2060-0558) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act. This is a proposed extension of the ICR, which is currently approved through March 31, 2018. Public comments were previously requested via the **Federal Register** 82 FR 44177 on September 21, 2017 during a 60-day comment period. This notice allows for an additional 30 days for public comments. A fuller description of the ICR is given below, including its estimated burden and cost to the public. An Agency may not conduct or sponsor and a person is not required to respond to a collection of information unless it

displays a currently valid OMB control number.

DATES: Additional comments may be submitted on or before April 30, 2018.

ADDRESSES: Submit your comments, referencing Docket ID Number EPA-R10-OAR-2017-0516, to (1) EPA online using www.regulations.gov (our preferred method), by email to R10-Public_Comments@epa.gov, or by mail to: EPA Docket Center, Environmental Protection Agency, Mail Code 28221T, 1200 Pennsylvania Ave. NW, Washington, DC 20460, and (2) OMB via email to oir_submission@omb.eop.gov. Address comments to OMB Desk Officer for EPA.

EPA's policy is that all comments received will be included in the public docket without change including any personal information provided, unless the comment includes profanity, threats, information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.

FOR FURTHER INFORMATION CONTACT:

Andra Bosneag, Office of Air and Waste, Environmental Protection Agency Region 10, 1200 Sixth Ave. Seattle, WA 98101; telephone number: (206) 553-1226; fax number: (206) 553-0110; email address: bosneag.andra@epa.gov.

SUPPLEMENTARY INFORMATION:

Supporting documents, which explain in detail the information that the EPA will be collecting, are available in the public docket for this ICR. The docket can be viewed online at www.regulations.gov or in person at the EPA Docket Center, WJC West, Room 3334, 1301 Constitution Ave. NW, Washington, DC. The telephone number for the Docket Center is 202-566-1744. For additional information about EPA's public docket, visit <http://www.epa.gov/dockets>.

Abstract: EPA promulgated Federal Implementation Plans (FIPs) under the Clean Air Act for Indian reservations located in Idaho, Oregon, and Washington in 40 CFR part 49 (70 FR 18074, April 8, 2005). The FIPs in the final rule, also referred to as the Federal Air Rules for Indian Reservations in Idaho, Oregon, and Washington (FARR), include information collection requirements associated with the partial delegation of administrative authority to a Tribe in § 49.122; the rule for limiting visible emissions at § 49.124; fugitive particulate matter rule in § 49.126, the wood waste burner rule in § 49.127; the rule for limiting sulfur in fuels in § 49.130; the rule for open burning in § 49.131; the rules for general open burning permits, agricultural burning permits, and forestry and silvicultural



E. SCOTT PRUITT
ADMINISTRATOR

March 13, 2018

MEMORANDUM

SUBJECT: Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program

FROM: E. Scott Pruitt

TO: Regional Administrators

In accordance with presidential priorities for streamlining regulatory permitting requirements for manufacturing, and in line with my prior recognition that “opportunities exist to simplify” the New Source Review process and thereby “achieve meaningful NSR reform,”¹ the U.S. Environmental Protection Agency has been undertaking an assessment of the agency’s implementation of the preconstruction permitting requirements under the NSR provisions of the Clean Air Act. As part of this assessment, the EPA has identified certain elements of the NSR regulations and associated EPA policies that have been sources of confusion and uncertainty.²

One such element that has given rise to uncertainty among both permitting authorities and stakeholders alike is whether emissions decreases from a proposed project at an existing major stationary source may be taken into account under Step 1 of the major modification applicability process in the EPA NSR regulations. The purpose of this memorandum is to communicate the EPA’s interpretation that its current NSR regulations provide that emissions decreases as well as increases are to be considered at Step 1 of the NSR applicability process, provided they are part of a single project. The EPA has at times indicated that the relevant provisions of the NSR regulations preclude the consideration of emissions decreases at Step 1, but for the reasons discussed below, the agency will no longer apply any such interpretation reflected in prior statements on this issue.³

¹ See Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783 (Oct. 25, 2017) at 3.

² See, e.g., “New Source Review Preconstruction Permitting Requirements: Enforceability and Use of the Actual-to-Projected-Actual Applicability Test in Determining Major Modification Applicability” (Dec. 7, 2017).

³ Thus, for example, the EPA no longer subscribes to the reading of the NSR regulations that is reflected in the Letter from Barbara A. Finazzo, U.S. EPA Region 2 to Kathleen Antoine, HOVENSA, LLC, “Re: HOVENSA Gas Turbine

1200 PENNSYLVANIA AVE. NW • MAIL CODE 1101A • WASHINGTON, DC 20460 • (202) 564-4700 • FAX: (202) 501-1450

Background

Under EPA regulations, the process for determining whether a project at an existing major stationary source triggers the requirement to obtain an NSR permit is a two-step process. Step 1 requires a determination of whether the proposed project, by itself, is projected to result in a significant emissions increase. If such an increase is projected to occur, the process moves to Step 2. Under Step 2, an evaluation is made as to whether the project will result in a significant *net* emissions increase, considering any other increases and decreases in actual emissions at the source that are contemporaneous with the particular project and are otherwise creditable. The EPA has generally referred to Step 2 as “netting” or “contemporaneous netting.”

In the past, the EPA has sometimes described the consideration of both increases and decreases in emissions under Step 1 of the NSR applicability process as “project netting.” The EPA now recognizes that using the term “project netting” at Step 1 has resulted in confusion among stakeholders, permitting authorities and within the EPA itself. A more appropriate term to characterize the consideration of a proposed project’s emissions increases and decreases at Step 1 is “project emissions accounting.” In the context of Step 1, the term “netting” is misplaced, insofar as “netting” more properly describes looking at those *other* projects that may have been or will be undertaken at a given facility over the contemporaneous period – i.e. an evaluation that takes place under Step 2. In contrast, “project emissions accounting” more accurately captures what Step 1 of the NSR applicability process is really all about – i.e. taking account of the true emissions impacts of the project itself.

The EPA believes that those prior agency statements that interpreted the NSR regulations as precluding project emissions accounting have had the practical effect of preventing certain projects from going forward and significantly delaying others, even though those projects would not have resulted in a significant emissions increase.⁴ The EPA recognizes that because of the inherent complexities associated with doing multi-year contemporaneous netting under Step 2 at a large facility,⁵ some companies may have been dissuaded from undertaking some projects. As a consequence, the EPA’s lack of clarity in this matter likely foreclosed projects with the potential to make production more efficient across a wide variety of industrial sectors. Such efficiencies can result in reduced emissions, even while production is maintained or expanded. The interpretation provided here is consistent with the language of the NSR regulations and should result in sounder regulatory outcomes.

Nitrogen Oxides (GT NOx) Prevention of Significant Deterioration (PSD) Permit Application- Emission Calculation Clarification” (March 30, 2010) (March 30 HOVENSA Letter).

⁴ See, e.g. National Mining Association Response to Request for Comments on Regulations Appropriate for Repeal, Replacement, or Modification Pursuant to Executive Order 13777, 82 FR 17,793 (Apr. 13, 2017), at 3-4, EPA-HQ-2017-0190-37770; Testimony of Paul Noe for Am. Forest & Paper Ass’n and Am. Wood Council, House Comm. on Energy & Commerce, Subcomm. on Env’t, Oversight Hearing on “New Source Review Permitting Challenges for Manufacturing and Infrastructure,” at 2, 5, 7-8 (Feb. 14, 2018) (“Noe Testimony”).

⁵ See, e.g. Noe Testimony at 7-8.

Relevant CAA and Regulatory Provisions

The NSR provisions of the CAA and the EPA's implementing regulations require that a preconstruction permit be obtained prior to beginning (1) the construction of a new major stationary source or (2) a "major modification" to an existing major stationary source. In general, preconstruction permits for sources emitting pollutants for which the area is designated attainment or unclassifiable and for other pollutants regulated under the major source program are called prevention of significant deterioration (PSD) permits. Permits for major sources emitting nonattainment pollutants and located in nonattainment areas are referred to as nonattainment NSR (NNSR) permits. The preconstruction permitting program, including the PSD and the NNSR permitting programs, is known as the NSR program.

The CAA contains no statutory definition of the term "major modification." The CAA does, however, define the term "modification" – i.e. "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4); CAA § 111(a)(4).⁶ Reflecting the fact that the preconstruction review provisions of the CAA's PSD and nonattainment area permitting programs are phrased in terms of the construction or modification of a "major emitting facility" (under the PSD program) and of a "major stationary source" (under the nonattainment program),⁷ The EPA's implementing regulations have from their earliest days been framed in terms of how one goes about determining whether a particular activity at an existing "major stationary source" will be deemed to be a "major modification."⁸ The EPA regulations specify that one determines whether a modification is "major" based on whether the modification results in an increase of emissions above specified rates defining whether the increase is "significant" (or greater than a *de minimis* amount).⁹

A project¹⁰ constitutes a major modification for a regulated NSR pollutant if (and only if) it would result in two types of emissions increases – i.e. a significant emissions increase

⁶ This definition of "modification," originally enacted by Congress in 1970 as part of the New Source Performance Standards (NSPS) program, was incorporated by reference for purposes of the newly enacted PSD and nonattainment programs by the Clean Air Act Amendments of 1977. See 42 U.S.C. § 7479; CAA § 169(C) ("The term 'construction' when used in connection with any source or facility, includes the modification (as defined in section 7411(a) of this title) of any source or facility."); 42 U.S.C. 7501 (4); CAA § 171 (4) ("The terms 'modifications' and 'modified' mean the same as the term 'modification' as used in section 7411(a)(4) of this title.").

⁷ 42 FR 57479, 57480 (Nov. 3, 1977).

⁸ See, e.g. 40 CFR § 52.21(a)(2) (1978).

⁹ See, e.g. 40 CFR § 52.21(a)(2) (2017). The EPA adopted this current approach after a court rejected the EPA's initial attempt to determine whether a modification was "major" based on the thresholds of 100 and 250 tons per year from the statutory definition of "major emitting facility." *Alabama Power v. Costle*, 636 F.2d 323, 399-400 (D.C. Cir. 2012); 44 FR 51924, 51937 (Sept. 9, 1979); 45 FR 52676, 57705 (Aug. 7, 1980).

¹⁰ A "project" is defined as "a physical change in, or change in the method of operation of, an existing major stationary source." 40 CFR § 52.21(b)(52).

(determined at Step 1), and a significant net emissions increase (determined at Step 2).¹¹ *See, e.g.* 40 CFR § 52.21(a)(2)(iv)(a).¹² These NSR applicability procedures, adopted as part of the 2002 NSR Reform rule,¹³ codified a prior EPA practice of looking first at whether any emissions increase that may result from the project itself would be significant before evaluating whether there would be a significant “net emissions increase” from the major stationary source as a whole.

The regulations further specify that the particular procedure for calculating whether a proposed project would by itself result in a significant emissions increase depends upon the type of emissions units that would be included in the proposed project.¹⁴ *See* 40 CFR § 52.21(a)(2)(iv)(b). These different procedures are required because, under the NSR regulations, the specific requirements for determining both the “baseline actual emissions” and the post-change “projected actual emissions” for existing emissions units are different than the requirements for determining the “baseline actual emissions” and the post-change “potential to emit” for new emissions units.

As relevant here, the NSR regulations currently provide as follows:

§ 52.21 Prevention of significant deterioration of air quality.

(a)(1) * * * *

(2) *Applicability procedures.* (i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in an area

¹¹ The net emissions increase is calculated as the sum of the emissions increase attributable to the particular project, calculated pursuant to 40 CFR § 52.21(a)(2)(iv), and any other increases and decreases in actual emissions at the major stationary source that are contemporaneous and otherwise creditable. *See* 40 CFR § 52.21(b)(3). Notwithstanding the interpretation of Step 1 communicated in this memorandum, source-wide netting (i.e. Step 2) will continue to have an important role in the NSR applicability process. For example, source-wide netting always will be needed, as appropriate, to allow for consideration of emissions associated with past projects within the contemporaneous period.

¹² This memorandum cites certain provisions in the federal PSD regulations at 40 CFR § 52.21(a)(2). The other NSR regulations, including 40 CFR § 51.166(a)(7), 40 CFR § 51.165(a)(2), and Appendix S of Part 51 (Part IV, Subpart I), contain analogous definitions and requirements, and the interpretation set forth in this memorandum also applies to those analogous provisions. However, there are certain modification provisions under the Title I, Subpart D of the CAA and the EPA nonattainment NSR regulations that apply to certain nonattainment area classifications (*see, e.g.* CAA § 182(e)(2); 40 CFR Part 51, Appendix S II.A.5.(v)). This memorandum does not address those specific modification provisions in the Act or the EPA regulations for nonattainment areas, and, thus, does not communicate any EPA view regarding interpretation of those provisions.

¹³ In 2002, the EPA issued a final rule that revised the regulations governing the major NSR program. 67 FR 80186 (Dec. 31, 2002). The agency refers generally to these rule provisions as the “NSR Reform rule.”

¹⁴ “Emissions unit” is defined, in relevant part, as “any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section.” 40 CFR § 52.21(b)(7). An “emissions unit” can be either a “new” unit or an “existing” unit, with a “new” unit being further defined as “any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.” *Id.* at § 52.21(b)(7)(i). An “existing emissions unit” is any unit that is not a “new emissions unit.” *Id.* at § 52.21(b)(7)(ii).

designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

* * * *

(iv) The requirements of the program will be applied in accordance with the principles set out in paragraphs (a)(2)(iv)(a) through (f) of this section.

* * * *

(b) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e. the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(iv)(c) through (f) of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (i.e. the second step of the process) is contained in the definition in paragraph (b)(3) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(c) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (b)(41) of this section) and the baseline actual emissions (as defined in paragraphs (b)(48)(i) and (ii) of this section), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(d) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (b)(4) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (b)(48)(iii) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(e) [Reserved]^[15]

¹⁵ While now designated as “reserved,” what had been clause (e) of 40 CFR § 52.21(a)(2)(iv) was promulgated as part of the 2002 NSR Reform rule. As originally promulgated, clause (e) read as follows:

(e) *Emissions test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

See 67 FR 80275. The Clean Unit provision of the 2002 NSR Reform rule was subsequently held to be unlawful and vacated by the U.S. Court of Appeals for the D.C. Circuit in *State of New York v. EPA*, 413 F.3d 3, 38-40 (D.C. Cir.

(f) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(2)(iv)(c) through (d) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

40 CFR § 52.21(a)(2)(iv)(b)-(f).

The EPA's Interpretation of the NSR Applicability Provisions

Based on the reconsideration of some previous conclusions and an examination of the regulations as a whole, the EPA now interprets the provisions set forth in 40 CFR § 52.21(a)(2)(iv)(c) through (iv)(f) as providing that any emissions *decreases* that may result from a given proposed project are to be considered when calculating at Step 1 whether the proposed project will result in a significant emissions increase. This interpretation is grounded in the principle that the “plain language of the CAA indicates that Congress intended to apply NSR to *changes that increase actual emissions.*” *State of New York v. EPA*, 413 F.3d at 40 (emphasis added). Central to the CAA’s definition of “modification” is that there must be a causal link between the physical or operational change at issue – i.e. the “project” – and any change in emissions that may ensue. In other words, it is necessary to account for the full and direct effect of the proposed change itself. Accordingly, at the very outset of the process for determining whether NSR may be triggered, the EPA should give attention to not only whether emissions may increase from those units that are part of the project but also whether emissions may at the same time decrease at other units that are also part of the project.

The use of the phrase “sum of the difference” in clauses (c) and (d) of 40 CFR § 52.21(a)(2)(iv) makes this clear. The “difference” between a unit’s projected actual emissions or potential to emit (following the completion of the project) and its baseline actual emissions (prior to the project) may be either a positive number (representing a projected increase) or a negative number (representing a projected decrease). In either case, the values that result from “summing” the “difference” are to be taken into consideration at Step 1 in determining the emissions impact of the project.

Some have argued that, in the case of projects involving only new units, the “sum of the difference” could never include a decrease in emissions, because the applicable test compares the potential to emit following the project to pre-project baseline actual emissions, which are equal to

2005). Thereafter, all of the regulatory language related to the Clean Unit provision, including clause (e) of 40 CFR § 52.21(a)(2)(iv), was stricken from the NSR Reform rule. See 72 FR 32526, 32528 (June 13, 2007). Also affected by the D.C. Circuit’s vacatur was certain language of clause (f) of 40 CFR § 52.21(a)(2)(iv) as it had originally been promulgated in 2002. Struck from clause (f) was a final sentence that provided: “For example, if a project involves both an existing unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(2)(iv)(c) of this section for the existing unit and using the method specified in paragraph (a)(2)(iv)(e) of this section for the Clean Unit.” See 67 FR 80275; 72 FR 32529.

zero.¹⁶ What this argument overlooks is that the NSR regulations define a “new unit” as “any emissions unit that is (or will be) newly constructed and that has existed *for less than 2 years* from the date such emission unit first operated” 40 CFR § 52.21(b)(7)(i) (emphasis added), and for a new unit “the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero,” and “thereafter, for all other purposes, shall equal the unit’s potential to emit.” 40 CFR § 52.21(b)(48)(iii). Therefore, following initial construction or permitting, a “new unit” (i.e. one that has existed for less than two years since it first operated) could, as the result of a particular project, experience a decrease in potential emissions – that is, the “sum of the difference” could be a negative number – if that project involved, for instance, the installation of controls on the unit, resulting in a decrease in the unit’s potential to emit.¹⁷

The phrase “sum of the difference” does not appear in clause (f) of 40 CFR § 52.21(a)(2)(iv). This omission, and the fact that clause (f) speaks of the “sum of the emissions increases,” led the EPA to say in a September 2006 notice of proposed rulemaking that this “challenges whether an emissions increase at an individual emissions unit can be a negative number.” See 71 FR 54249 (Sept. 14, 2006). While the EPA went on to say that it was “reasonable to conclude that a source can perform project netting for hybrid [projects] as well,” the agency also indicated that the “current rule . . . would not allow a source to include reductions from units that are part of the project until Step 2 of the calculation.” *Id.* It was on that basis that the EPA proposed new regulatory language that was directed at making it explicit that emissions decreases as well as increases would be accounted for at Step 1 for projects involving both existing and new units. *Id.* at 54252.

Based on a more thorough consideration of the surrounding context in the regulations, the EPA finds that the negative inference which the agency drew in 2006 from the fact that the phrase “sum of the difference” is absent from clause (f) was unwarranted.¹⁸ Other language in clause (f)

¹⁶ It was on this basis that the EPA previously said that, because the “sum of the difference” for a project that only involves new emissions units must entail summing only emissions increases, this result should also inform the reading of the “sum of the difference” as the phrase is applied to projects involving only existing units, leading to the conclusion that taking account of emissions decreases at Step 1 is not permitted at all. See March 30 HOVENSA Letter at 5. As was previously noted, the EPA no longer subscribes to the reading of the NSR regulations reflected in the March 30 HOVENSA Letter.

¹⁷ In its March 30 HOVENSA Letter, the EPA also stated that “EPA would not have needed to provide a special provision and unique rationale for the replacement unit rule if EPA had intended to allow project netting under the 2002 NSR Reform Rule.” March 30 HOVENSA Letter at 4. But this does not follow. Absent the provision, a replacement unit would be deemed a new emissions unit to which the actual-to-potential test would apply instead of the actual-to-projected-actual test applicable to existing units (including replacement units). This difference between the two applicability tests remains regardless of whether emissions decreases are accounted for at Step 1.

¹⁸ This negative inference previously led the EPA to adopt the view that this provision did not allow “project netting,” 71 FR at 54249, and thus that it was necessary to propose an amendment to 40 CFR § 52.21(a)(2)(iv)(f) to allow project emissions accounting for hybrid projects. 71 FR at 54251. Since the EPA no longer considers the negative inference to be warranted, the agency also does not believe it is necessary to finalize the proposed 2006 revision before project emissions accounting can be conducted in Step 1 of the NSR applicability analysis for hybrid projects. However, the EPA is not taking action at this time to withdraw the project netting elements of the 2006 notice of proposed rulemaking. The EPA is still evaluating whether a revision of the text of 40 CFR § 52.21(a)(2)(iv)(f) is desirable to provide additional clarity on this issue.

indicates that emissions decreases are also to be accounted for. Clause (f) specifically provides that the “sum of the emissions increases for each emissions unit” is to be calculated *after* the specific impact of the proposed project has been ascertained with respect to each type of unit involved, “using the method specified in paragraphs (a)(2)(iv)(c) through (d) of this section *as applicable with respect to each emission unit.*” (emphasis added). That is, for a project involving both existing and new units, this accounting is to be done on a unit type-by-unit type basis, in which both emissions decreases (if any) and emissions increases (if any) are to be taken into consideration.

Moreover, the history of this provision in the regulations indicates that the EPA originally intended that project emissions accounting be allowed at Step 1 for projects involving different types of units. The concluding “For example . . .” sentence that had originally been part of clause (f) but which had been stricken (for unrelated reasons) when the Clean Unit provision was vacated, *see* note 15 above, illustrates the agency’s intention. That sentence provided that, where a proposed project involves different types of units, the determination whether there is a projected increase is to be made by “summing the *values determined using* the method specified in paragraph (a)(2)(iv)(c) of this section for the existing unit and using the method specified in paragraph (a)(2)(iv)(e) of this section for the Clean Unit.” (emphasis added). If one were to substitute “new unit” for “Clean Unit” and “paragraph (a)(2)(iv)(d)” for “paragraph (a)(2)(iv)(e),” by way of providing a different “example,” the point remains. Since the “values” derived from calculating the “sum of the difference” with respect to both existing units and new units could be a negative number, the language used in clause (f) – “sum of the emissions increases” – presents no “challenge” to the use of project emissions accounting, i.e. taking account of emissions decreases as well as emissions increases, under the current regulatory language pertaining to projects that involve both existing and new units.

The EPA does not interpret the existing regulations as requiring that a decrease be creditable or enforceable as a practical matter in order to be considered at Step 1. The issue of whether an emissions decrease is creditable and enforceable is relevant to Step 2, but not to Step 1. Regarding this, in the 2002 NSR Reform rule, the EPA expressly declined to adopt a requirement under which a source’s post-project projected actual emissions would have become an enforceable emission limitation. Such an approach had previously been suggested by the EPA, but the agency ultimately rejected it. *See* 67 FR 80193, 80197. The same reasoning that underpinned the 2002 NSR Reform rule’s treatment of projected actual increases applies equally to projected emissions decreases at Step 1. One exception to this is where an emissions decrease is calculated using the potential to emit of a unit after the project. In such a case, the requirements of 40 CFR § 52.21(b)(4) would continue to apply.

The EPA also promulgated, as part of its adoption of provisions addressing the use of the “projected actual emissions” methodology, provisions pertaining to the tracking, documenting, and, under certain circumstances, the reporting of post-project emissions increases. *See, e.g.* 40 CFR §§ 52.21(b)(41), 52.21(r)(6). Those provisions would impose on sources the same obligations with respect to emissions decreases taken account of at Step 1. Given this, the EPA should not treat projected increases and projected decreases differently at Step 1, by requiring that decreases

be “credible” and “enforceable,” as would be the case with contemporaneous decreases accounted for at Step 2.¹⁹

Finally, it is important to point out that project emissions accounting, as described above, is a calculation that is done in conjunction with ascertaining, prior to beginning actual construction, the applicability of NSR to a particular project at a source that the owner/operator is itself *proposing* to undertake. In this regard, the EPA recognizes that as a general matter, the source itself is responsible for defining the scope of its own “project,” subject to the understanding that the source cannot seek to circumvent NSR by characterizing the proposed project in a way that would separate into multiple projects those activities that, by any reasonable standard, constitute a single project. Subject to the equivalent understanding that it might be possible to circumvent NSR through some wholly artificial grouping of activities, the EPA does not interpret its NSR regulations as directing the agency to preclude a source from reasonably defining its proposed project broadly, to reflect multiple activities. The EPA will speak more to this issue in planned upcoming action on “project aggregation.”

* * * *

The EPA Regional Offices should send this memorandum to states within their jurisdiction. For any questions concerning this memorandum, please contact Anna Marie Wood in the Office of Air Quality Planning and Standards at (919) 541-3604 or wood.anna@epa.gov.

¹⁹ In the September 2006 notice of proposed rulemaking, the EPA had proposed to adopt regulatory language that specified, for the purposes of what was then termed “project netting,” that emissions decreases must be credible or otherwise enforceable as a practicable matter. *See* 71 FR 54252. At that time, the EPA provided no explanation why it considered such a requirement to be either necessary or warranted, and the agency now recognizes that other provisions in existing regulations serve to alleviate concerns that projected emissions decreases would escape the same tracking, documentation and reporting requirement applicable to projected emissions increases. As discussed in footnote 18, the EPA is not withdrawing the September 2006 proposal at this time, pending further consideration of whether a revision of the regulatory text is desirable to provide further clarity.



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

APR 05 2018

Ms. LeAnn Johnson Koch
Perkins Coie
700 13th Street, NW
Suite 600
Washington, D.C. 20005-3960

Re: Limetree Bay Terminals, St. Croix, U.S. Virgin Islands – Permitting Questions

Dear Ms. Johnson Koch:

This is in response to your February 1, 2018, letter to the U.S. Environmental Protection Agency's (EPA) Region 2 Office, in which you sought EPA's concurrence on three New Source Review (NSR) permitting questions pertaining to the Limetree Bay Terminals (LBT) facility in St. Croix, U.S. Virgin Islands (USVI). In your letter, you specifically asked whether EPA concurs with LBT that:

- (1) restarting some of the idled refinery units as part of the "MARPOL Project"¹ (to produce fuel compliant with the maritime sulfur regulations taking effect January 2020) will not result in the facility being viewed as a new stationary source under EPA's current so-called Reactivation Policy;
- (2) the MARPOL Project and another LBT project to produce Renewable Diesel Fuel are independent and should not be considered a single project for purposes of applicability under the Prevention of Significant Deterioration (PSD) regulations; and
- (3) the addition of a deeper water loading configuration (Single Point Mooring or SPM) should be considered a modification to an existing emissions unit (i.e., the dock system and associated loading terminal) and not a new emissions unit for the PSD applicability analysis.

In addition to the foregoing inquiries, you previously sought EPA guidance regarding when emission decreases from a project can be considered within the NSR applicability analysis.

¹ MARPOL is the International Convention for the Prevention of Pollution from Ships.

Based on EPA's review of your submitted analyses and supporting documents, we concur that: (1) restarting of the refinery's idled units for the MARPOL Project should not be treated as a new stationary source under the current Reactivation Policy; (2) the MARPOL Project and the Renewable Diesel Fuel Project are independent of each other and therefore separate projects for PSD applicability; and (3) constructing the SPM would be considered a modification to an existing emissions unit rather than a new emissions unit. Discussion on each of these issues is provided below, along with information to address your previous question regarding accounting of emission decreases within the NSR applicability analysis.

Restarting Refinery Units and the Current Reactivation Policy

The current policy on the reactivation of sources provides that a major stationary source that has been idled for 2 or more years is presumed to be permanently shut down. *See In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc.*, Proposed Operating Permit, Petition No. 6-99-2 (June 11, 1999). That policy states that if a source is permanently shut down, upon reactivation it is considered a "new" stationary source for purposes of PSD review. Accordingly, PSD applicability would be based on the reactivated source's potential to emit.

Importantly, however, this 2-year presumption is rebuttable. EPA will not consider the shutdown to have been permanent upon the owner or operator of the source making a demonstration that, at the time of the shutdown, and continuously throughout the shutdown period, they intended to restart the facility. Among the factors that EPA in the past has considered in evaluating the owner or operator's intent are:

- Length of time the facility has been shut down and concrete plans for restart;
- Statements by the owner or operator of intent;
- The cause of the shutdown;
- Status of permits, including but not limited to Clean Air Act operating permits, acid rain permits and other required permits, and emission inventory;
- Maintenance and inspections during shutdown; and
- Time and capital needed to restart.

In evaluating these factors, no single factor is likely to be conclusive in determining intent. Instead, EPA generally has considered the totality of all such factors and the relevant supporting documentation in evaluating whether there was a continuous intent to restart the facility.²

In the case of LBT's facility in St. Croix, our review of the information you have submitted leads us to conclude that both LBT and HOVENSA displayed a continuous intent to restart the refinery operations. Therefore, applying the criteria of the current Reactivation Policy, we have determined that LBT's St. Croix facility was not permanently shut down and should not be considered a "new source" for purposes of PSD applicability.

² As this description indicates, the current Reactivation Policy has been derived from a series of EPA site-specific determinations and guidance issued over the course of many years. Further, EPA has not cited any specific regulatory provisions of the NSR program to support its position on source "reactivation." We are applying the current Reactivation Policy to resolve the LBT issue, but we intend to reconsider the policy in the near future.

LBT's facility in St. Croix was previously owned by HOVENSA until 2016, at which time LBT purchased the refinery and terminal operations. As LBT explains, an economic downturn caused HOVENSA to idle the refinery operations in 2012. Nevertheless, since that time, the terminal operations, wastewater treatment plant, and power generation have continued to operate at this location. Even before HOVENSA announced, on February 21, 2012, that it had completed the final idling of all refinery units, HOVENSA had informed the USVI government of its plans to retain its permits and implement maintenance procedures on their equipment so that it could restart the refinery. LBT represents that over the next several years, HOVENSA spent over \$400 million to maintain the restart capability of the refinery operations, which included removing residual material from equipment, retaining control room operability, and conducting other process equipment mothballing activities.

LBT provided EPA with a timeline and supporting information that included evidence of this continuous intent by HOVENSA and LBT to restart the facility. The supporting information included company statements, press releases, and various correspondence from 2011 through 2017. LBT also confirmed that HOVENSA and LBT maintained all environmental permits in active status and submitted timely renewal applications. Further, LBT stated that these companies continued to comply with the Refinery MACT, NSPS Subpart J, and all of the applicable RCRA regulations while the refinery units were idled. LBT represents that the companies maintained critical refinery equipment, such as compressors, pumps, utilities, wastewater treatment units in working order and conducted multiple walkthrough inspections at the plant, activities that are necessary for a restart. In order to demonstrate that the maintenance activities were performed, LBT provided a list of critical equipment and the timeline of significant maintenance activities performed at the refinery. LBT also represents that neither it nor HOVENSA made any statements to any party or issued any press release indicating any intent *not* to restart the plant in the future.

Project Aggregation – Renewable Diesel Project and Refinery Restart (MARPOL Project)

The term “project aggregation” describes the process of grouping “nominally separate changes that are sufficiently related based on established criteria ... into a single common project for the purpose of determining PSD applicability.”³ More specifically, the emissions of the nominally separate changes are combined for the purposes of determining whether a “significant emissions increase” – referred to as “Step 1” of the NSR applicability test – will occur from the project. EPA’s project aggregation policy aims to ensure the proper permitting of modifications that involve multiple physical and/or operational changes. Where the projects at issue are more reasonably deemed to constitute a single project for purposes of NSR, a source will not be allowed to circumvent major NSR by seeking to permit the individual activities separately under minor source NSR.

³ Letter from Stephen Page, Director, Office of Air Quality Planning and Standards, to David Isaacs, Vice President, Government Policy, Semiconductor Industry Association (August 26, 2011). (SIA Letter)

LBT plans to construct the Renewable Diesel Project and the MARPOL Project at the current plant site in late 2018. Given that these projects will begin close in time to one another, LBT has sought EPA's concurrence that these projects should not be aggregated (i.e., considered to be a single project) for the purposes of the PSD applicability analyses. LBT representatives have been clear in statements to EPA that, while they are pursuing the Renewable Diesel Project and the MARPOL projects concurrently, they are separate and distinct projects. Based upon EPA's review of all the information LBT provided, we concur that the two projects are independent of each other and, therefore, should not be aggregated for purposes of PSD applicability.

In analyzing whether the two LBT projects at issue here should be aggregated, we have followed our current policy on project aggregation, which takes into account indicia of relatedness among the individual actions at a source in order to determine whether the activities, in the aggregate, are one physical or operational change as those terms are used in the statute and regulations.⁴ Our policy on aggregation outlines an approach relying upon case-specific factors (e.g., timing, funding, and the company's own records) and the relationship between nominally separate changes.

As explained in your letter, the MARPOL Project involves restarting certain existing refinery units to process crude oil, heavy fuel oil, and petroleum intermediates into refined petroleum products. This project will involve restarting a crude unit, a reformer, two naphtha hydrotreating units, a coker unit, two distillate hydrotreating units, an isomerization unit, and two sulfur recovery plants. These units will be configured to produce low-sulfur fuels (i.e., gasoline, diesel, and fuel oil) and are scheduled to begin operation just before January 2020, when the relevant MARPOL amendments and EPA implementing regulations take effect. LBT represents that the economic viability of the MARPOL Project depends on the value generated from converting petroleum crude into refined petroleum products and market advantages that may exist due to an anticipated market shortfall of MARPOL-compliant marine fuel in 2020.

Your letter explains that the proposed Renewable Diesel project will convert vegetable, animal, and recycled cooking oils into renewable diesel fuel. This project involves building a feedstock pretreatment train and a new hydrogen unit to convert the oils into diesel compounds, and repurposing an existing hydrotreating unit (previously used for the hydrotreating of petroleum liquids) as the reactor for the conversion. LBT represents that the Renewable Diesel Project will produce fuel meeting the requirements of the Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS) programs, and that the fuel could be blended with transportation fuel sold in the United States to generate Renewable Identification Numbers (RINs) under the RFS as well as LCFS credits. Further, LBT suggests that the renewable diesel fuel may be eligible for a federal blender's tax credit. According to LBT, the economic viability of the Renewable Diesel Project depends heavily on the future value of converting vegetable, animal, and recycled cooking oils into renewable fuel, as well as the value of RINs, LCFS, and other tax credits. Significantly, none of these factors relate to the MARPOL project.

⁴ While EPA issued a revised policy on project aggregation in 2009, the policy has been stayed and is currently under reconsideration by the Agency. See 74 FR 2376 (January 15, 2009), 74 FR 7193 (Feb. 13, 2009), 75 FR 27643 (May 18, 2010). See 75 FR 19570-71 (April 15, 2010) for a collection of memoranda that provide examples of EPA's current approach to project aggregation.

LBT has shown that each of these two projects is technically distinct and does not depend on the other in terms of decision-making and timing, interaction between units, the process technologies used, feedstocks involved, or products produced. LBT stated that the MARPOL Project will be fully self-contained as the selected units are inspected, reconditioned as needed, and restarted. More specifically, LBT maintains that the raw materials, piping, process equipment, and material transfer systems for each project will be completely unshared and independent of the other project. LBT represents that the construction of one project does not necessitate or otherwise influence the construction of the other project.

LBT has demonstrated to our satisfaction that the economic viability of each project stands on its own, such that the Renewable Diesel Project could proceed on its own financial merits, regardless of the future of the MARPOL Project, and vice versa. In particular, LBT noted the unique opportunity presented to timely and economically reconfigure the idled hydrotreating equipment and the current availability of renewable fuel and tax credits as proof of lack of economic dependency between the Renewable Diesel and MARPOL Projects. Each project's feasibility is based on its own set of incentives and market realities and does not depend on the other project going forward.

We note that the one thing that may be considered to be common to both projects is the potential for shared utilities. However, sharing utilities does not in and of itself mean that activities at a source are functionally or economically dependent on one another. Since both projects will produce fuel gas, the power and steam required to operate each project can be generated from fuel gas produced by either the renewable diesel unit or the MARPOL refining unit, and in some cases the projects may combust fuel oil, so neither project is dependent on the other project for steam or power generation. In addition, LBT stated that each project will rely on the existing wastewater treatment and water production facilities at the terminal. LBT maintains there is no appreciable cost benefit that the Renewable Diesel Project will receive by virtue of the MARPOL Project because the utilities are already in operation as part of the ongoing terminal operations.

Single Point Mooring – Modification to an Existing Emission Unit

LBT also seeks a determination that the addition of a single point mooring (SPM) project to its existing marine loading/unloading system should be considered a modification to an existing unit at the facility rather than a new unit pursuant to the PSD regulations. In your letter, you explain that the existing marine loading/unloading system consists of ten marine docks, each of which can load and unload multiple petroleum products. According to LBT, the proposed SPM addition would “extend from the jetty on the seabed for approximately 5,800 feet to a Pipeline End Manifold” that would be connected to a buoy via a flexible hose, and the buoy would load/unload crude oil onto ships via two floating hoses.

Based on the information provided by LBT, EPA believes that the addition of the SPM is reasonably considered to be an extension of the existing marine loading terminal. Therefore, EPA concludes that the SPM should be treated as a modification of the existing marine terminal emissions unit.

The definition of “emissions unit” in the PSD regulations does not speak to how broadly or narrowly to consider the scope of an emissions unit at a stationary source, nor does it address how to treat a new emissions point, such as the SPM, that is added to an existing stationary source with existing emission units. The definition at 40 CFR §52.21 (b)(7) states:

Emissions unit means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section:

- (i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.
- (ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.

This regulatory language can be reasonably interpreted to provide that multiple pieces of related process equipment (or emission points) comprise a single emissions unit.

Prior EPA determinations interpreting the PSD regulations provide specific guidance on this question. Those determinations illustrate that ascertaining the proper scope of an “emissions unit” often requires very case- and fact-intensive analyses. For instance, in a letter to the Semiconductor Industry Association, EPA confirmed that it was appropriate to treat an entire semiconductor fabrication building, or “fab,” as one emissions unit.⁵ EPA based this decision on the “interconnected nature of the ‘tools’ in the fab” and the systems that deliver materials and manage discharges. The letter also pointed out that fab units could be located in adjoining buildings if they are “physically connected, integrated, and operated” in a continuous and consolidated manner, and that it may be more appropriate to treat physically separated operations as a separate emissions unit. In that letter, EPA also referenced other determinations by EPA Regions, in which the Regional office provided rationale for why grouping related processes and equipment into a single emissions unit made sense given the circumstances.⁶

In analyzing the SPM project, we note that the existing marine terminal currently loads and unloads crude oil in addition to other petroleum products. Based on the information provided in LBT’s recent permit application to the Virgin Islands Department of Planning and Natural Resources, the SPM will load and unload only crude oil. Since LBT is currently loading and

⁵ SIA Letter.

⁶ Letter from Judith M. Katz, Region III, U.S. EPA, to John M. Daniel, Director, Air Program Coordination, Commonwealth of Virginia, Department of Environmental Quality, (November 30, 2000); Letter from Douglas M Skie, Region VIII, U.S. EPA, to Brad Beckham, Director, Air Pollution Control Division, Colorado Department of Health (February 6, 1990).

unloading crude oil at the existing marine terminal, the proposed SPM would not change the nature of the pollutant-emitting activity occurring at the terminal. Furthermore, the SPM will be physically connected to the existing marine loading terminal by way of an underwater piping system and will be completely integrated with the loading and storage operations at the existing terminal. Consequently, the SPM and current marine terminal appear to share the same interconnectedness that EPA previously found persuasive in its analysis of semiconductor fabs, which supports treating LBT's proposed SPM and the existing terminal as a single emissions unit.

We also note that state agency permit actions have also reflected the flexibility within the definition of emissions unit. There are several examples of state permitting agencies treating multiple marine loading berths/docks as a single emissions unit in the context of Title V permits.⁷ Thus, the treatment of multiple loading docks or berths as a single emissions unit is not unusual.

Finally, in other correspondence LBT has informed EPA that it will be installing a vapor capture and collection system at the existing marine terminal, although LBT has indicated the system will not be used to reduce emissions that occur while loading ships at the SPM. Instead, LBT has indicated it intends to comply with the submerged loading requirements⁸ when the ships are loaded at the SPM, and that the control of emissions from the existing docks will help offset the emission increases from the operation of the SPM. We note that, in the context of the PSD program, a BACT determination for a major modification is focused on each emissions unit. However, this approach does not foreclose a determination that different emission points within an emissions unit can have distinct BACT requirements due to technical or economic feasibility or other factors considered under a BACT review. Consequently, for LBT to install a vapor recovery system at the existing loading berths and apply a different control strategy for the SPM emission point does not necessitate that the SPM be treated as a separate emissions unit under the PSD program. EPA views the proposed SPM and the new vapor control system as being part of the overall integrated loading/unloading operation at the terminal, and views this operation as an integrated emissions unit for PSD purposes.

Consideration of Emission Decreases from the Project

While not specifically raised in your February 1, 2018 letter, LBT previously asked EPA whether, under the NSR applicability procedures (e.g., 40 CFR §52.21(a)(2)), emission decreases may be taken into account when a "significant emissions increase" calculation of projects which involve only existing units is undertaken at Step 1 of the NSR applicability analysis. As you should be aware, EPA has recently clarified that emission decreases from a project are to be considered at Step 1. This applies not only to existing emission units for but all categories of projects. *See* Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program (March 13, 2018).

⁷ *See, e.g.*, Indiana Department of Environmental Management, Part 70 Operating Permit, BP Products North America, Inc. – Whiting Business Unit (December 14, 2006); Commonwealth of Virginia, Department of Environmental Quality, Federal Operating Permit, TransMontaigne Operating Company, L.P. – Norfolk Terminal (April 7, 2014). EPA is also aware of analogous non-marine loading activities, such as truck loading racks, being treated as a single emissions unit.

⁸ 46 CFR 153.282.

Conclusion

EPA's responses contained within this letter are based on the information LBT has provided EPA through letters and emails pertaining to your permitting questions. Since EPA does not have emissions information and other specifics regarding your planned projects, EPA is not providing any final determination on the applicability of the PSD regulations to your projects. A final determination on PSD applicability will be made on the basis of the information provided in your application and supporting materials. Finally, nothing in this letter's discussion of PSD policies should be interpreted to reflect EPA's views on the applicability or requirements of any other programs, including the New Source Performance Standards and the National Emissions Standards for Hazardous Air Pollutants.

If you have any questions about this letter, please contact Anna Marie Wood in the Office of Air Quality Planning and Standards at (919) 541-3604 or wood.anna@epa.gov.

Sincerely,

A handwritten signature in black ink, appearing to read 'W L Wehrum', written in a cursive style.

William L. Wehrum
Assistant Administrator

cc: Alexander Dominguez
David Harlow
John Filippelli
Bill Harnett
Peter D. Lopez
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